REGIONAL POWER-TO-X CONCEPT

Techno-economic assessment and overview of regulative aspects

Lappeenranta–Lahti University of Technology LUT

LUT School of Energy Systems

Energy Technology

Master’s Thesis

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Henrik Larjava

Examiner(s): Prof. Tero Tynjälä, Postdoc. Eero Inkeri

Supervisor(s): M.Sc. Henri Karimäki

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Lappeenrannan–Lahden teknillinen yliopisto LUT

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Energiatekniikka

Henrik Larjava

Alueellinen power-to-x konsepti

Teknis-taloudellinen arviointi ja katsaus ajankohtaisiin ohjausmekanismeihin

Energiatekniikan diplomityö

134 sivua, 62 kuvaa, 20 taulukkoa ja 5 liitettä

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Avainsanat: PtX, P2X, PtM, RED, Fit For 55, RFNBO, Säädökset, Elektrolyysi, Metanointi

Diplomityön tarkoituksena oli tutkia power-to-x (PtX) kenttää ja tämänhetkisiä säädöksiin liittyviä näkökohtia EU:n ja kansalliselta tasolta. Lisäksi työssä tehtiin teknis-taloudellinen arviointi alueelliseen PtX konseptiin. Työssä tarkasteltiin myös PtX prosessiin liittyviä teknologioita ja näistä tehtiin yleiskatsaus. Yleiskatsaus sisälsi elektrolyysin, hiilidioksidin talteenoton ja polttoainesynteesiin liittyviä asioita. Prosessien päätuotteet sekä sivuvirrat ja niiden hyödyntämisen mahdollisuudet tuotiin esille.

Säädöksiin liittyvät näkökohdat keskittyivät EU:n Fit For 55 pakettiin ja niiden vaikutusten arviointiin PtX alaa koskien. Kansallisen tason säännöksiä esitettiin myös. Säädökset liittyen PtX alaan ovat vielä valtaosin keskeneräisiä ja kehityksen asteella. Säädökset vaikuttavat PtX teknologioiden laajamittaiseen soveltamiseen, mutta ne tarvitsevat vielä lisäselvityksä ja viimeistelyä.

Alueellisen PtX konseptin pää- ja sivutuotteiden hyödyntäjät tunnistettiin paikallisten mahdollisuuksien perusteella. Työssä tehtiin PtX ekosysteemin analyysi jossa mahdolliset keskeiset sidosryhmät, heidän roolit, arvotekijät ja ohjaavat säädökset tunnistettiin.

Teknis-taloudellisessa arvioinnissa tutkittiin metanointi vaihtoehtoja erilaisissa kysyntä skenaarioissa. Alkalielektrolyysiin perustuva metanointi saavutti tuottavan skenaarion mikäli synteettisen metaanin (SNG) vuosittainen tuotanto ylitti n. 6000 tonnia 145 €/MWh referenssi myyntihinnalla. Kiinteäoksidielektrolyysiin perustuvassa metanoinnissa saavutettiin tuottava skenaario vuosituotannon ylittäessä n. 23700 tonnia. Happi ja hukkalämpö sivuvirtojen hyödyntäminen laski vedyn ja synteettisen metaanin tuotantokustannuksia. Sähkön hinta, huipunkäyttöaika, elektrolyysin hyötysuhde ja skaalaus vaikuttivat merkittävästi metanoinnin tuotantokustannuksiin.

ABSTRACT

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The purpose of this Thesis was to research the field of power-to-x (PtX) and the current regulative aspects on the EU and national level. Furthermore, a techno-economic assessment was prepared for a regional PtX concept. A technology overview of different PtX process components was evaluated which included electrolysers, carbon capture and fuel synthesis. Their associated main products and side streams and their utilisation potential were identified as well.

The regulative aspects concerning EU Fit For 55 packages was analysed and their impact to the field of PtX. Current regulation status on a national level was also presented. The results indicated that the field of regulation is incomplete at this stage and is on a development status. Regulation will affect the potential of wide-scale application of PtX technologies; however further clarification and finalisation is needed.

The regional PtX concept main product off-takers and side stream utilisation targets were identified based on local opportunities. A PtX ecosystem analysis of possible key stakeholders was completed and their roles as well as regulation and value drivers were uncovered.

The techno-economic assessment evaluated the feasibility of methanation plant alternatives in different demand scenarios. Alkaline electrolyser based methanation resulted in a feasible scenario when the production of synthetic natural gas (SNG) exceeded approx. 6 kt/a with a reference sales price of 145 €/MWh. Solid oxide electrolyser based methanation resulted in a feasible scenario only if SNG was produced by at least 23.7 kt/a. Oxygen and heat revenues were found to reduce the levelized costs of hydrogen and SNG. Electricity costs, full load hours, electrolyser efficiency and scaling had a large impact on the costs of methanation.

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I would like to thank my employer, Wärtsilä, for giving the opportunity to complete my master's studies alongside my daily work. In addition, I would like to extend my gratitude to the X-Ahead project team for providing the topic for this Thesis and for the interesting discussions and workshops. Furthermore, to everyone who participated in the interviews or provided additional insight for this work, your input has been very helpful and enlightening.

I want to thank all my family and friends who have supported me along the way. A special thank you goes to Marjolein for enduring me throughout the writing process and providing the support and care that was needed. Without your support, it would have been a rockier journey.

Sincerely,

Henrik

SYMBOLS AND ABBREVIATIONS

Symbols

E_s	Specific energy consumption [kWh/kg]
G	Gibbs energy change [kJ/mol]
H	Enthalpy [kJ/mol]
I_0	Initial investment [€]
k	Ratio of specific heats
m	Mass flow rate [kg/h]
M	Molar mass [g/mol, kg/kmol]
n	number of stages
P	Pressure [bar]
P_{comp}	Compressor power [kW]
P_d	Compressor design power [kW_e]
P_{elec}	Electrolyser rating [kW, MW]
P_{SNG}	Methanation rating [kW, MW]
R	Universal gas constant [8.3144 kJ/kmolK]
r	Discount rate [%]
S	Entropy [kJ/K]
SC_{elec}	Electrolyser system consumption [kWh/kg]
T	Temperature [K, °C]
U_{rev}	Reversible voltage [V]
U_{tn}	Thermoneutral voltage [V]
Z	Compressibility factor
η	Efficiency

Abbreviations

AEL	Alkaline Electrolyser
BEV	Battery Electric Vehicle
BoP	Balance of Plant
CAM	Cathode Active Materials
CAPEX	Capital Expenditures
CBAM	Carbon Border Adjustment Mechanism
CcH_2	Cryo-compressed Hydrogen
CCO_2	Compressed Carbon Dioxide
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilisation
CCUS	Carbon Capture Utilisation and Storage
CfD	Contract for Difference
CGH_2	Compressed Gaseous Hydrogen
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
DAC	Direct Air Capture
DC	Demand Scenario
E&A	Electrical and Automation
ECBM	Enhanced Coalbed Methane Recovery
EGR	Enhanced Gas Recovery
EOR	Enhanced Oil Recovery
EoS	Economies of Scale
EPC	Engineering Procurement and Construction
ESR	Effort Sharing Regulation
ETD	Energy Taxation Directive
ETS	Emission Trading System
EUA	Emission Allowances
FC	Fuel Cell
FEED	Front End Engineering Design
FLH	Full Load Hours
GHG	Greenhouse Gas
GHSV	Gas Hourly Space Velocity
GO	Guarantees of Origin
GTK	Geological Survey of Finland
HHV	Higher Heating Value
ICE	Internal Combustion Engine
IPCC	Intergovernmental Panel on Climate Change
LCO_2	Liquefied Carbon Dioxide
LCOH	Levelized Cost Of Hydrogen
LCOSNG	Levelized Cost Of Synthetic Natural Gas
LH_2	Liquid Hydrogen
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LSHFO	Low Sulphur Heavy Fuel Oil
LULUCF	Land Use Land Use Change and Forestry
MDO	Marine Diesel Oil
MEA	Monoethanolamine
MSW	Municipal Solid Waste
MTG	Methanol-To-Gasoline
MTO-MOGD	Methanol-To-Olefins-Mobil´s Olefins to Gasolines and Distillates
NPV	Net Present Value
OPEX	Operational Expenditures
PEM	Proton Exchange Membrane electrolyser
PHEV	Plug-in Hybrid Electric Vehicle
PPA	Power Purchase Agreement
PtL	Power-to-Liquid
PtM	Power-to-Methane
PtX or P2X	Power-to-X
RED	Renewable Energy Directive
RES	Renewable Energy Source
RFNBO	Renewable Fuels of Non-Biological Origin
RRT	Rail-Road Terminal
SAF	Sustainable Aviation Fuels
SMR	Steam Methane Reforming
SNG	Synthetic Natural Gas
SOEC	Solid Oxide Electrolyser Cell
STP	Standard Temperature and Pressure
TEN-T	Trans-European Transport Networks
TtW	Tank-to-Wake
WtE	Waste-to-Energy
WtT	Well-to-Tank
XtP	X-to-Power

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1 Introduction

The need for sustainable and low emission energy systems is greater than ever. According to the recent Sixth Assessment Report from the Intergovernmental Panel on Climate Change (IPCC), human activities have caused an increase in global average temperature levels of approximately 1.1 °C since 1850 – 1900 due to greenhouse gas (GHG) emissions. (IPCC 2021) As stipulated in the Paris Agreement that entered into force in 2016, the target is to limit the temperature increase to 1.5 °C or well below 2 °C from pre-industrial levels. (United Nations 2015) Considering the IPCC report, it indicates that exceeding the minimum target level of 1.5 °C temperature increase in the next decades is imminent, unless significant and fast climate change mitigation plans are implemented. (IPCC 2021)

The call to action is clear. While the temperature increase might not seem significant, further global temperature rise increases the frequency of extreme weather conditions which in turn can cause significant financial damages and population displacement.

On a national level, the Finnish government has made plans to amend the national Climate Change Act. The amendment has the objective that Finland aims to be carbon neutral[1] by 2035. The purpose of the amendment is to strengthen the Acts regulatory impact in achieving the emission reduction targets. (Valtioneuvosto 2021)

The greenhouse gas emissions in Finland have been steadily declining in recent years. While the year 2020 was exceptional in many ways, the reduction in annual emissions was due to warmer winter, changes in electricity production structure and cyclical fluctuations in industry. The effect of the pandemic was seen in the reduction of transport emissions according to the proxy estimation of 2020. Total emissions have declined by approximately 9 % from 2019 and 32 % from 1990 respectively. The annual total emissions from 1990 to 2020 for Finland can be seen in the following figure. (OSF 2021a)

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[1] As per the IPCC definition, carbon neutrality (or net zero CO_2 emissions) is achieved when anthropogenic CO_2 emissions are balanced by the removal of anthropogenic CO_2 emissions over a specific time frame. (IPCC 2018)

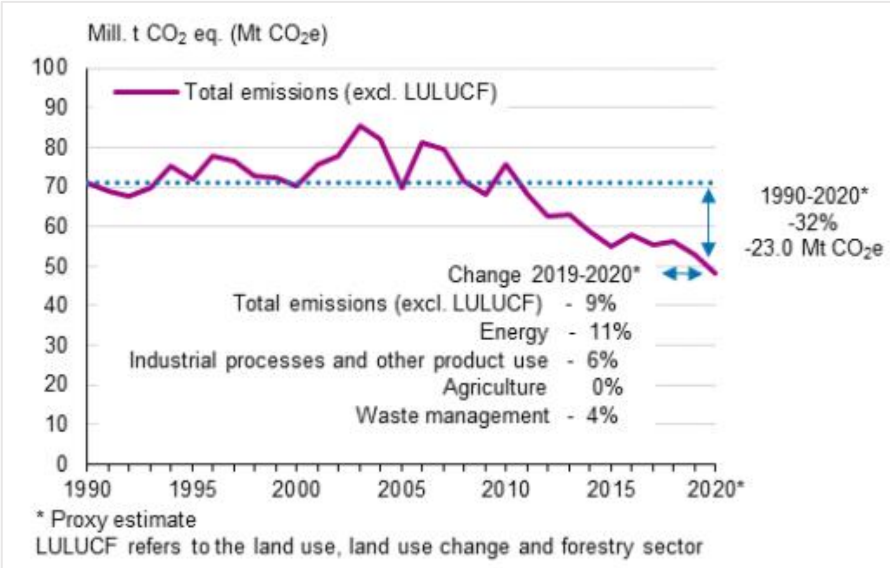


Figure 1. Annual total GHG emissions in MtCO2eq in Finland without Land Use Land Use Change and Forestry (LULUCF) sector from 1990 to 2020. (OSF 2021a)

For the pre-pandemic year, the emission distribution by sector is illustrated in the figure below.

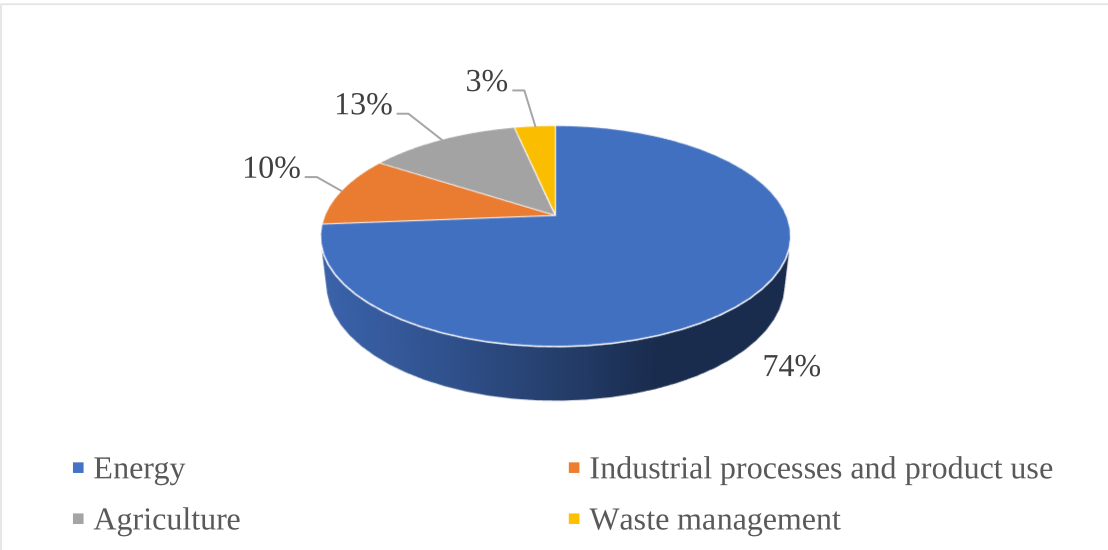


Figure 2. Distribution of annual GHG emissions by sector in 2019. Without LULUCF. (OSF 2021a)

The energy sector is the main contributor in Finnish annual emissions, resulting in approx. 39.1 MtCO2eq in 2019. Transport sector is included in the energy emissions of which its contribution was approx. 11.3 MtCO2eq in 2019 which corresponds to approx. 21 % of total emissions (OSF 2021a). Transitioning to a low carbon emission energy sector will be crucial in reaching the ambitious carbon neutrality targets.

Power-to-x (PtX or P2X) technologies are the most promising alternatives in decarbonizing[2] energy-systems. The term power-to-x includes a variety of different methods of converting electric "power" generation into different products "x" which can be fuels, industry feed-stock, plastics, chemicals and even food (P2XEnable 2021). The following figure illustrates a simplified overview of power-to-x process.

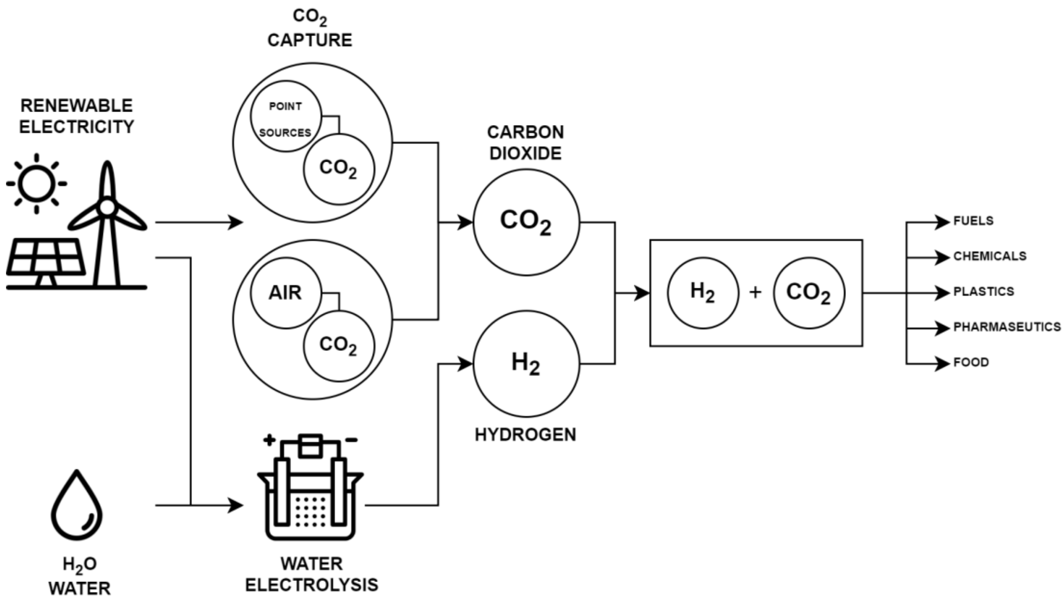


Figure 3. Overview of power-to-x process. Adapted from (P2XEnable 2021).

PtX technology would also solve the problem of intermittent renewable energy production from wind and solar power by providing the means to store the electricity. Generated electrical energy is used to produce hydrogen via electrolysis which is then synthesized with captured CO_2 from air or flue gases to create hydrocarbons which results in renewable synthetic fuels. Hydrogen and renewable fuels would act as the energy storage for variable renewable energy production and provide flexibility (Sterner, Stadler 2019, 20). Renewable fuels and hydrogen can be used in transportation, heating and industrial sectors and when their primary energy source is (renewable) electricity, the method is defined as sector coupling (Sterner, Stadler 2019, 28). This method would reduce emissions significantly across

[2] Decarbonisation refers to carbon emission reduction in the sector. (IPCC 2018)

number of sectors due to increased renewable energy integration to the system, resulting in faster achievement of emission reduction targets.

Hydrogen economy is enabled by PtX technology and it requires more investments, research and development as well as promotion to be able to mature in the future. The Finnish Hydrogen Cluster estimates that annual GHG reduction of 4 – 6 MtCO2eq could be achieved by utilising green hydrogen (H2Cluster 2021). Reaching carbon neutrality targets requires the adoption of green hydrogen and PtX ecosystems which makes this study highly topical.

1.1 Background and motivation

This study is part of Wärtsilä´s X-Ahead program which is aimed to increase the knowledge and expertise in power-to-x technology and commercial aspects. The program is designed for collaboration with research partners to investigate the business potential of PtX systems and to promote the transition of Finnish economy towards carbon neutrality. Transitioning to a 100% renewable electricity system is part of Wärtsilä´s strategy for the future. (Wärtsilä 2021a, 38)

The city of Vaasa has announced that it aims to be a carbon neutral city by 2035. In addition, there are several multimillion-euro investment projects planned or ongoing in the region. The development projects are related to sustainable energy solutions and emission reduction. (City of Vaasa 2021)

The strategy from Wärtsilä and initiatives set by the city of Vaasa indicate that exploring the potential of PtX application in the region will give suitable means of reaching the ambitions for decarbonisation.

In addition, the field of PtX is complex in terms of technical aspects as well as regulation aspects. Understanding the field holistically can likely improve the success rate of actual implementation.

1.2 Previous work

Development of PtX projects has been growing fast in recent years in Europe. Most of the PtX demonstration projects in Europe are concentrated in Western Europe. Main countries increasing PtX project development are France and Germany, each country with planned electrolyser installation capacity of approx. 500 MW by 2025. According to the study of 220 European demonstration projects, just a third was focused on further processing hydrogen into fuels or products with methane being the most preferred choice of hydrogen processing route, followed by methanol. It was also noted that the utilisation of oxygen side stream from electrolyser process had received very little focus. Most of the projects required public financial support for being realized. (Wulf et al. 2020, 5, 9, 11)

Domestic industrial size feasibility study for a pilot installation for carbon neutral fuel production has been completed recently by LUT University together with research partners. The pilot facility design (P2X Joutseno) was based on utilising excess hydrogen from a chemical processing plant and capturing CO_2 from flue gases of a cement production plant. Methanol synthesis was the main pathway with additional synthesis routes from methanol to produce gasoline, kerosene and diesel. Additional hydrogen production via water electrolysis was also studied. (Laaksonen et al. 2021, 5)

The main finding for the economic feasibility of the P2X Joutseno pilot plant is the cost of hydrogen from either the purchase of excess hydrogen or hydrogen generated with water electrolysis. Hydrogen produced via alkaline electrolysis was not found profitable due to electricity costs diluting the profits from estimated fuel sales. It was noted that side stream (oxygen and heat) sales would increase the profitability of the water electrolysis alternative. Production location of electricity and hydrogen together with the source location of CO_2 was found to have an impact in the profitability due to costs related to transportation, storage and site related production costs. Regulation concerning synthetic fuels was found to be inconclusive and lacking for promoting carbon neutral fuels. Estimated savings on GHG emissions with PtX fuels compared to fossil fuels was found to be significant with excess hydrogen and with electrolysis case when renewable energy is used. (Laaksonen et al. 2021, 6, 7, 68, 84)

Another recent pre-study in Finland was done for Meri-Pori region in which a methanation plant for producing synthetic natural gas with an alkaline electrolyser and CO_2 captured from nearby sources, concluded that the project was not profitable without further production subsidies. Electricity costs versus revenues from produced fuel was found as the main reason for feasibility. From side streams, only heat was utilised fully since there was not found suitable consumers nearby for oxygen. (Lindström 2021, 35, 36, 37)

1.3 Research objective, questions and methods

The objective of this research is to find out the regulatory framework and economic aspects which impact the PtX ecosystem and its processes. Furthermore, a case study will be examined based on the findings and an overall optimum setup will be proposed for Vaasa region.

Optimum proposal for the case study presents the main research problem. The supporting research questions to which this study aims to provide answers are:

- Where and who are the main key stakeholders and off-takers?
- What main products and side streams are utilised by who and how?
- Which technologies are favoured for main products and side streams and their geographical locations?
- Which regulations and value drivers are impacting the PtX ecosystem?

The methods to obtain the answers are:

- Literature research for the technology, regulations and economic topics
- Techno-economic model for the case study
- Interviews of key persons within PtX topic in Vaasa region

The hypothesis for this work is that the electricity costs and utilisation of electrolyser side streams will have a great impact on the case study feasibility.

The next section will describe the scope for this study.

1.4 Scope framework

Limitations of scope are necessary as the topic can cover a wide range of alternatives which can inflate the workload drastically. The aim of this study is to provide a holistic view for the regional PtX case.

The scope of work for this thesis is limited to gathering high level system information of the PtX technologies relevant for the proposed case study. Necessary regulatory and economic aspects concerning the case study are presented.

The case study will be limited to the region of Vaasa, Finland in which the stakeholders, off-takers and technologies are evaluated based on findings. Furthermore, the results presented in chapter 87 from stakeholder interviews will define the scope as well.

1.5 Structure of the Thesis

The next chapter will present the PtX technologies considered for this study. Third chapter will focus on the regulatory considerations. Fourth chapter evaluates the economic aspects. The key stakeholders and off-takers mapping for the Vaasa region case study will be presented in chapter five. Finally, the case study will be presented and discussed with concluding remarks.

2 PtX technology review

This chapter presents the technology review from literature. Suitable technologies are investigated to fit the case study. The main outputs from different technologies are defined as the primary product produced towards utilisation by an off taker. Side streams are defined to be a source of additional revenue or a stream that needs to be discharged or handled in a suitable manner.

2.1 Sources of energy for hydrogen production

For this study, the sources for energy for the PtX process is defined as the input energy required to produce hydrogen which will be the feedstock for further synthesis or a product for direct end use. Hydrogen can be categorised with the energy source used for the hydrogen production. The following table illustrates the different colour identifications for different hydrogen production pathways.

Table 1. Hydrogen colours with different production pathways. (H2Cluster 2021, 6; National Grid 2022)

Hydrogen colour		**Energy source**	**Technology**
Grey	Turquoise	Natural gas	Steam methane reforming (Grey) Methane pyrolysis with solid carbon (Turquoise)
Brown	Black	Coal, Oil	Gasification
Blue		Natural gas / Coal, Oil	Steam methane reforming / gasification with carbon capture and storage (CCS)
Pink		Nuclear power	Water electrolysis
Green		Renewable electricity	Water electrolysis

However, there is no universally agreed official colour coding for hydrogen production, so the definitions can vary.

Currently, the most common energy source used for hydrogen production is natural gas together with steam methane reforming. Natural gas accounted for 59 % from total global hydrogen production of 90 Mt in 2020. Approximately 79 % of total hydrogen production was done using fossil fuels sources. The following graph illustrates the distribution of global hydrogen production sources. (IEA 2021a, 108)

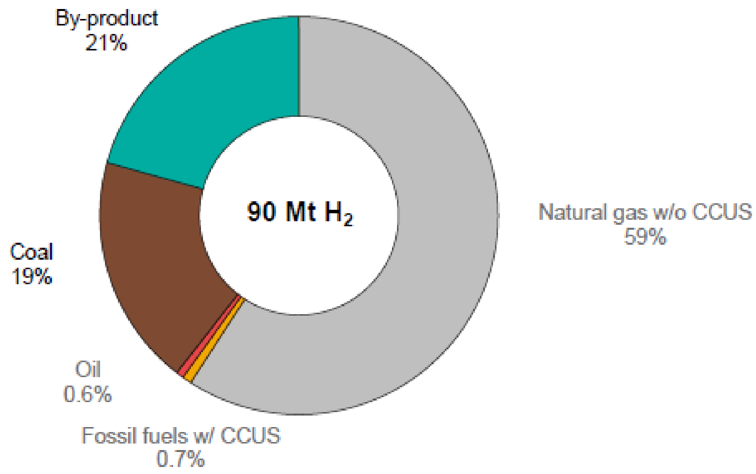


Figure 4. Global hydrogen production distribution by source in 2020. (IEA 2021a, 108)

By-product hydrogen is the result of hydrogen formation when producing other products such as reformation of naphtha to gasoline in a refinery (IEA 2021a, 108). Water electrolysis accounted for approx. 0.03 % of total hydrogen production in 2020 (IEA 2021a, 109).

The annual dedicated hydrogen production in Finland amounts to approx. 140000 – 150000 ton. Additionally, by-product hydrogen is produced via sodium chloride electrolysis which amounts to approx. 22000 – 24000 ton annually. Majority of the dedicated hydrogen production is produced with steam reforming or partial oxidation of fossil fuels. Water electrolysis accounts for less than 1 % of dedicated hydrogen production. Most of the dedicated hydrogen production (approx. 88 %) is utilised for refining oil and producing biofuels. By-product hydrogen is mainly used for heat generation for district heating and process steam. The distribution of hydrogen utilisation in Finland is presented in the following figure. (Laurikko et al. 2020, 21)

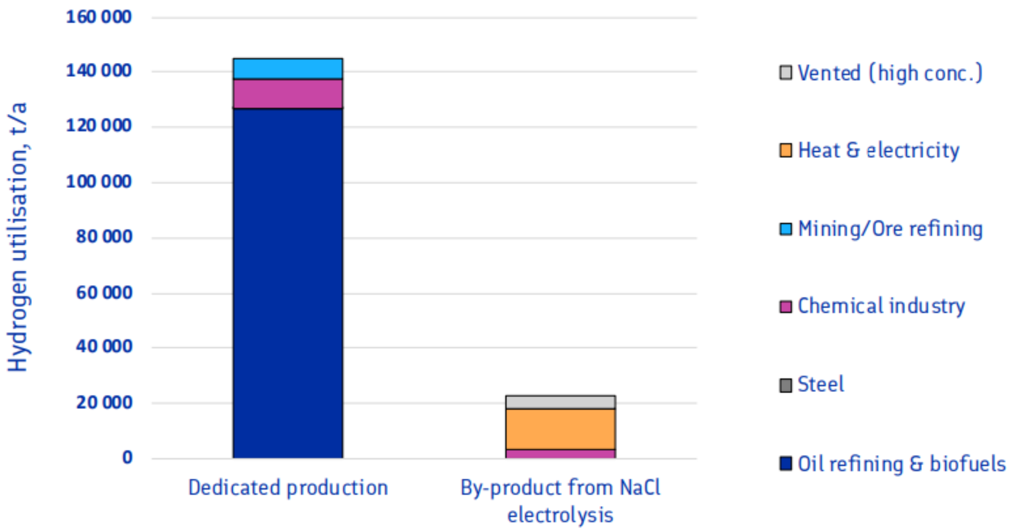


Figure 5. Annual hydrogen utilisation in Finland. Steel industry usage of approx. 200 t/a and thus not visible. (Laurikko et al. 2020, 21)

It is evident that majority of the global hydrogen is produced with fossil fuel resources today, which presents an opportunity for increasing renewable hydrogen in the production chain. This study will focus on green hydrogen and water electrolysis, so no further analysis will be concluded for other production methods.

2.2 Green hydrogen production

To produce green hydrogen with water electrolysis, renewable and low emission electricity is required such as solar and wind. In Finland, wind power could be utilised in green hydrogen production. In the end of 2021, the cumulative installed wind power generation capacity in Finland reached 3257 MW which contributed 8061 GWh in annual electricity production (FWPA 2022a). Wind power accounted for 11.7 % and 9.3 % of annual electricity production and consumption, respectively (FWPA 2022a). The potential of increasing wind power production is significant according to the published wind power projects that were under planning in 2021 which amounted to 21300 MW in total (FWPA 2021a). Although, most of the projects might not be realised, it indicates a massive growth opportunity for wind power generation.

Ostrobothnia region is suitable for large scale wind energy production as the region is located on the west coast of Finland with favourable wind conditions. The wind resources and annual production estimates for a 3 MW wind turbine are available from the Finnish Wind Atlas which are presented in the following figure.

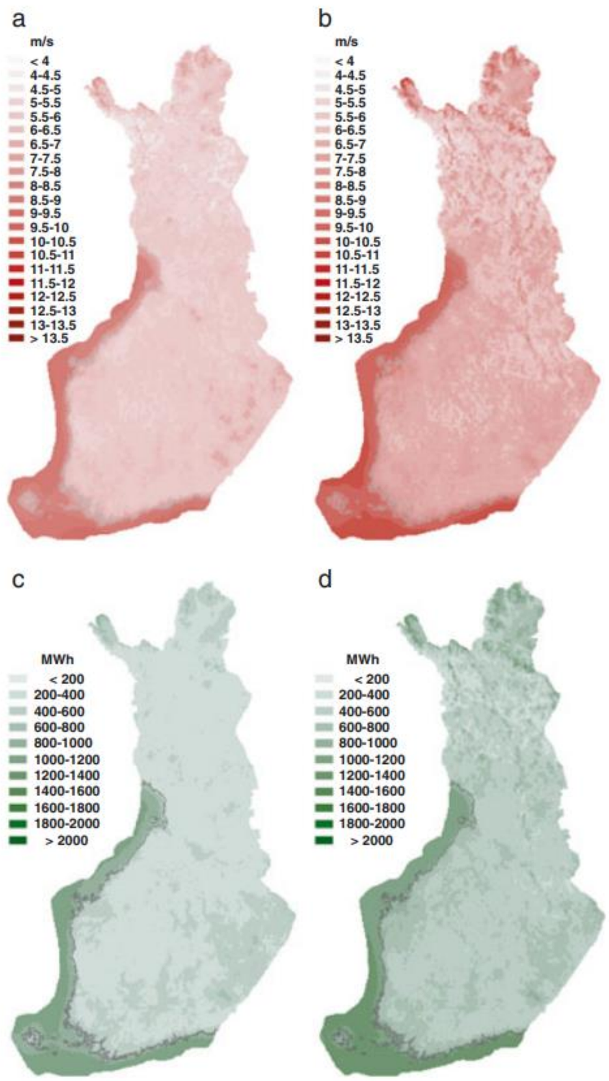


Figure 6. Wind speeds at 100 m height in May (a) and December (b). Annual production estimate for a single 3 MW wind turbine in May (c) and December (d).(Tammelin et al. 2013, 31)

The largest wind power producer nearby Vaasa is EPV Tuulivoima Oy, with 53 MW in operation and 90 MW in planning (FWPA 2021b). In addition to the wind power potential, the cost of wind power has been steadily declining in recent years. In a cost price study of different electricity generation alternatives in Finland, onshore wind energy emerged as the cheapest electricity production method with 41.44 €/MWh which has reached lower costs than e.g. nuclear power which was 42.36 €/MWh (Vakkilainen, Kivistö 2017, 12). Although wind power cannot provide similar baseload electricity generation as e.g. nuclear power, it is meaningful to pursue the potential of it together with green hydrogen production. The transition towards more renewables requires adoption of energy storage alternatives to which PtX could be a potential candidate.

2.3 PtX process components

This section will describe the main components of a power-to-x process and their characteristics together with output products and possible side streams. The focus point for PtX process in this study is the hydrogen production and further synthesis into transport and power generation fuels. The following figure illustrates the simplified process considered for this study.

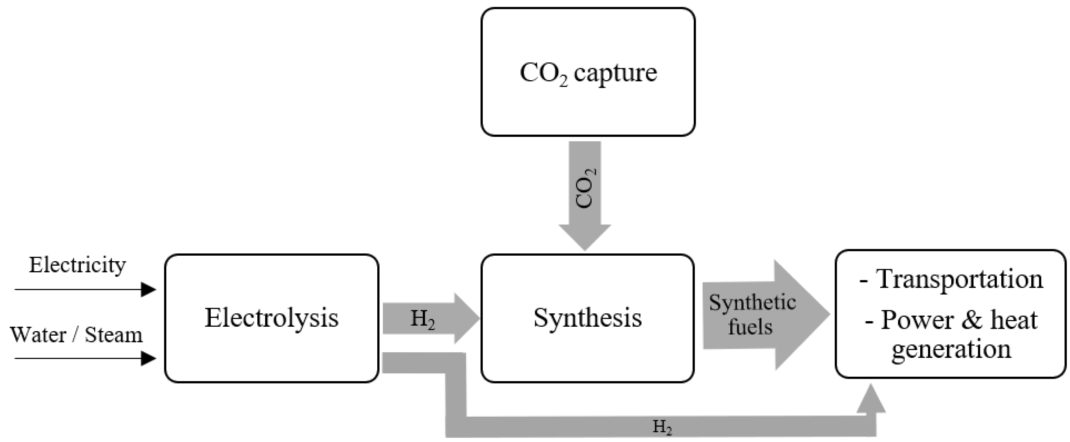


Figure 7. Simplified power-to-x process.

The next chapters will describe the components and their main operating principles.

2.3.1 Electrolysis

Water electrolysis is an electrochemical process used to split water into hydrogen and oxygen gas. The process is non-spontaneous and requires external energy, which is supplied to the process as electrical energy. The complete reaction for water electrolysis (1) and the thermodynamic energy (2) for water splitting can be expressed as follows. (Buttler, Spliethoff 2018, 1-2; Sterner, Stadler 2019, 340)

$$\mathrm{H_2O}(l) \xrightarrow{\text{electrical energy}} \mathrm{H_2}(g) + \frac{1}{2}\mathrm{O_2}(g) \tag{1}$$

$$\Delta H = \Delta G + T\Delta S \tag{2}$$

Where ΔH is the reaction enthalpy or the overall energy demand in kJ/mol, ΔG is the Gibbs energy change in kJ/mol, T is temperature in K and ΔS is the entropy change as $S_{H_2} + S_{O_2} - S_{H_2O}$ in kJ/K.

By using the thermochemical table (NIST 2013) values for eqn. (2), we can get the following results for the reaction energy for water splitting in liquid and vapour states at 25 °C (298.15 K, 1 bar) and 127 °C (400 K, 1 bar) respectively.

$$\mathrm{H_2O}(liquid) \rightarrow \Delta H = \overbrace{237.1\ \mathrm{kJ/mol}}^{\text{electricity}} + \overbrace{48.7\ \mathrm{kJ/mol}}^{\text{heat}} = 285.8\ \mathrm{kJ/mol} \tag{3}$$

$$\mathrm{H_2O}(steam) \rightarrow \Delta H = \overbrace{223.9\ \mathrm{kJ/mol}}^{\text{electricity}} + \overbrace{19.9\ \mathrm{kJ/mol}}^{\text{heat}} = 243.8\ \mathrm{kJ/mol} \tag{4}$$

The theoretical minimum voltages are discussed in conjunction with the reaction energy, these are described as the reversible voltage U_{rev} and thermoneutral voltage U_{tn} of the electrolyser cell. The reversible cell voltage indicates the minimum voltage for initiating water splitting and the thermoneutral voltage indicates minimum voltage without heat input which is typical for commercial electrolysers where heat is generated with electricity. These theoretical values at 25 °C and 1 bar are U_{rev} = 1.23 V and U_{tn} = 1.48 V. Current density, which is typically indicated as A/cm^2 for different electrolysers, influences electrolyser performance together with temperature and pressure. Electrolyser efficiency reduces over time (degradation) due to increase in current density, decreasing of temperature and slightly with increasing operating pressures. (Buttler, Spliethoff 2018, 2; Ursua, Sanchis 2012, 4)

Detailed descriptions of the electrochemistry of the electrolysis process are omitted since it is not in the scope of this study. The following graph illustrates the energy demands as a function of temperature for water and steam electrolysis.

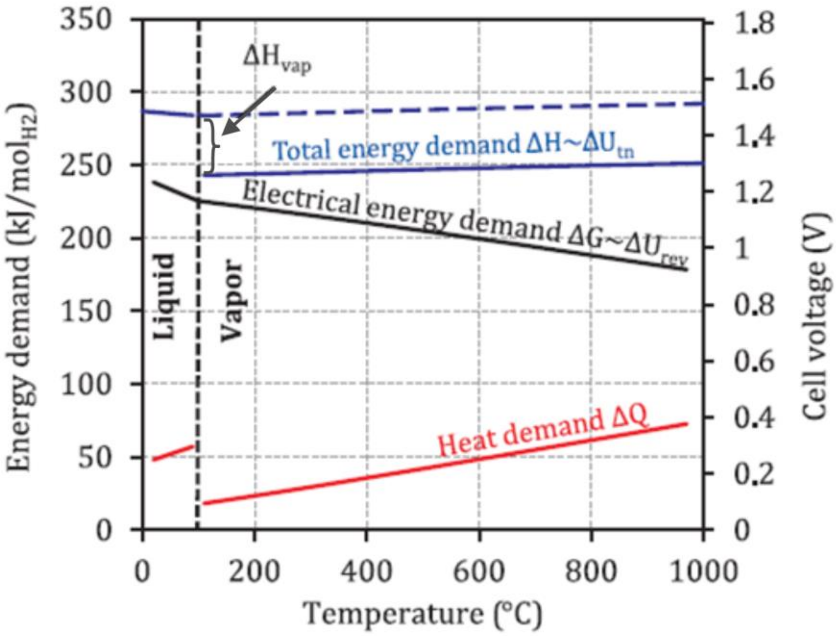


Figure 8. Thermal (ΔQ=$T\Delta S$), electrical (ΔG) and total (ΔH) energy demand of an ideal electrolysis process. Modified from (Buttler, Spliethoff 2018, 2).

As it can be seen from eqn. (4) and the above graph, by increasing the electrolysis temperature, the electrical energy consumption can be reduced. In water electrolysis, the total energy demand is generated with electricity as the heat is produced inside the cell due to internal resistances, so in case of low temperature electrolysis, external cooling is needed. In steam electrolysis, the heat demand increases and it is supplied to the process as steam, making it a suitable alternative for coupling with a high temperature heat source such as a combined heat and power (CHP) plant. The above graph illustrates an ideal process and in practice, electrolysers operate above these ideal values and require more energy. Electrolyser efficiency can then be expressed as follows (Harrison et al. 2010, 9; Koponen 2020, 32).

$$\eta_{el.HHV(orLHV)} = \frac{HHV_{H_2}\left(or\ LHV_{H_2}\right)}{E_s} \tag{5}$$

Where:

HHV_{H_2} Higher heating value of hydrogen [39.4 kWh/kg or 3.54 kWh/Nm^3]

LHV_{H_2} Lower heating value of hydrogen [33.3 kWh/kg or 3.00 kWh/Nm^3]

E_s Specific energy consumption of an electrolyser [kWh/kg or kWh/Nm^3]

When indicating the efficiency of an electrolyser, it should be clearly stated that which heating value it is based on. Specific energy consumption is typically specified in electrolyser manufacturer product technical datasheets. In case of steam electrolysis, the additional heat supplied should be considered in the overall energy consumption of the system.

2.3.1.1 Electrolyser categorisation and key operating parameters

Electrolysers can be categorised in low temperature (LT) and high temperature (HT) electrolysis technologies. LT electrolysers typically operate below 100 °C and HT electrolysers operate above 100 °C, typically in the range of 700 - 1000 °C. Two commercially available LT electrolysers are alkaline electrolyser (AEL) and proton exchange (or polymer electrolyte) membrane electrolyser (PEM). HT electrolysers are currently under development stage, and they are based on solid oxide electrolyser cell (SOEC) technology.

AEL based electrolysers operate in a liquid electrolyte which typically consists of a 25-30 wt.% potassium hydroxide (KOH) aqueous solution. The nickel coated electrodes (anode and cathode) are separated with a gas tight diaphragm made of zirconium dioxide. Hydrogen is produced on the cathode side and oxygen on the anode side, this is true for all electrolyser technologies. Alkaline solution poses a corrosion risk for electrode materials, however AEL's are the most mature and proven technology with lowest capital costs. (IRENA 2020, 32; Ursua et al. 2012, 8-9)

PEM electrolysers differ from AEL in terms of the electrolyte and electrode materials. The electrolyte in a PEM electrolyser consists of a gas tight solid polymer membrane, typically made of Nafion thus not requiring an alkaline solution. The anode and cathode materials are commonly iridium and platinum respectively. Utilising noble metals increases production costs and accelerating manufacturing volumes could be subjected to material scarcity bottleneck issues if material recycling is not addressed, especially concerning iridium. PEM electrolysers are starting to gain traction in industrial scale applications. (IRENA 2020, 32; Minke et al. 2021, 2; Ursua et al. 2012, 9)

SOEC electrolysers utilise a solid ceramic electrolyte for the electrolyte and it is typically made of yttria-stabilized zirconia (YSZ). The anode consists of a perovskite type material such as lanthanum manganite and the cathode is typically a combination of nickel and YSZ. Some challenges occur in the hydrogen production in the cathode side since hydrogen gas and steam need to be separated which increases capital costs. In addition, air might be used as a sweep stream in the anode to remove the oxygen product, so the stream would exit as oxygen enriched air, which might need additional preparation if high purity oxygen is needed. High temperature operation can increase likelihood of issues regarding operational stability and sealing. As mentioned already, SOEC electrolysers are in development phase, however some MW scale demonstration projects are currently being implemented. (Buttler, Spliethoff 2018, 5; IRENA 2020, 32; Ursua et al. 2012, 11)

The following figure illustrates the operation principles of the three electrolyser technologies.

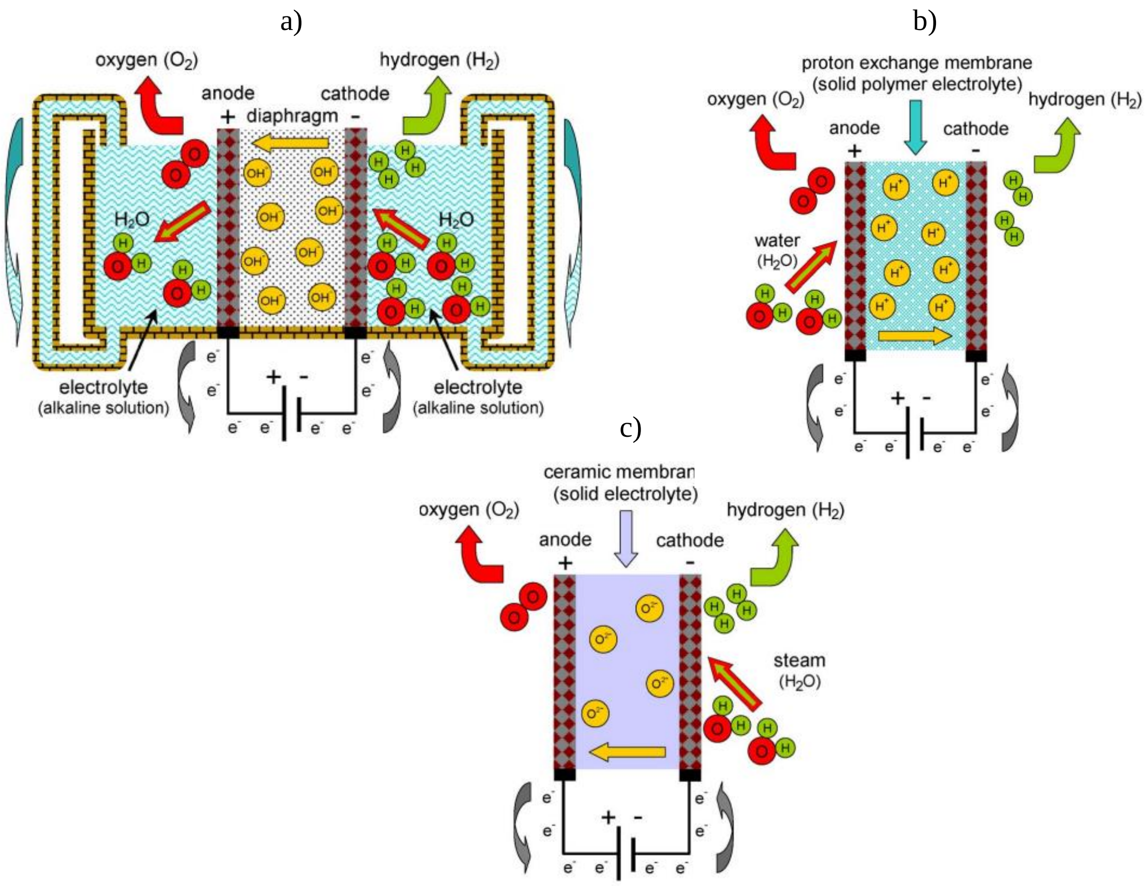


Figure 9. Operation principles of a) AEL, b) PEM and c) SOEC electrolysers. (Ursua et al. 2012, 9, 10, 11)

Electrolyser plants typically include multi-cell stack configurations which are modularly scalable. Some key parameters of the different technologies are presented in the table below.

Table 2. Key parameters of different electrolyser technologies.

Electrolyser technology	**AEL**	**PEM**	**SOEC**
Module [kW] / system size [MW]	5-6000 / 100 [1]	5-2500 / 100 [1]	225 / 2.68 [2]
Efficiency [%, LHV] - System level, including auxiliaries and heat for SOEC	51-60 [3]	46-60 [3]	76-81 [3]
System energy consumption [kWh/Nm^3]	5.0-5.9 [3]	5.0-6.5 [3]	3.7-3.9 [3]
Operating temperatures [°C]	60-95 [1]	50-80 [1]	700-1000 [1]
Operating pressures [bar]	1-30 [1]	1-40 [1]	1-3 [1]
Stack lifetimes[h]	55000-120000 [3]	60000-100000 [3]	< 20000 [3]
Efficiency degradation rate [%/a]	0.25-1.5 [3]	0.5–2.5 [3]	3-50 [3]
Hydrogen purity [%]	99.99-99.998 [4]	99.9995 [4]	99.99 [2]
Flexible loading [%]	20-100 [3]	0-100 [3]	5-100 [2]
Start-up time cold / warm	1-2 h / 1-5 min [3]	5-10 min / <10 s [3]	Hours / 15 min [3]
Water conductivity requirements [µS/cm]	< 5 [5]	< 1 [5]	n/a
Feed water consumption [l/Nm$^3_{H2}$]	~1 [4]	~0.9 [4]	n/a
Steam consumption [kg/h] / pressure [bar] / temperature [°C]	n/a	n/a	860 / 3.5-5.5 / 150-200 [2]
Technical development stage	Mature [6]	Commercial [6]	Demonstration [6]

Note. Values collected from: ([3]: Buttler, Spliethoff 2018, 12; [4]: Nel Hydrogen 2021, 4-6; [2]: Sunfire 2020, 2; [6]: Tenhumberg, Büker 2020, 3; [1]: Trattner et al. 2021, 3; [5]: Ursua et al. 2012, 9-10)
n/a = not applicable

The above table is not exhaustive as several research papers and manufacturers quote various values for different technologies. In addition, the research and development of electrolyser technologies is accelerating so technical parameters are developing constantly.

However, some key elements can be noted, such as, the start-up time and flexible loading which PEM electrolysers seem to have an advantage if cold starts are required in e.g., variable renewable electricity operation with frequent starts and stops. Otherwise in warm idling mode, all electrolysers should be able to respond to variable power generation. The efficiency degradation rate is the largest with SOEC although there is a high uncertainty due to the technology being in development phase. Water conductivity requirements set water purification needs for the AEL and PEM electrolysers, feed water treatment is typically included in the electrolyser plant system.

Regarding system energy consumption, if pressurized output of the hydrogen gas is required, typically for storage reasons, the power consumption for compression should be included.

In addition, if the SOEC electrolyser is not coupled with a high temperature heat source, the total energy consumption can increase to similar levels as AEL and PEM technologies due to thermal energy requirement. (Tenhumberg, Büker 2020, 5)

Auxiliary systems are needed for the electrolyser plant to operate. The typical balance of plant (BoP) components for electrolysers are described in the following table.

Table 3. BoP components of electrolysers. (Zhao et al. 2020, 10)

BoP component	AEL	PEM	SOEC
Water/steam delivery system	Water purification	Water purification	Heat exchanger
Power conversion	Transformer, rectifier	Transformer, rectifier	Transformer, rectifier
Stack	AEL stack	PEM stack	SOEC stack
Oxygen gas system	Separator w/ cooling jacket	Separator w/ cooling jacket	Separator
Hydrogen gas system	Hydrogen purification	Hydrogen purification	Heat exchanger
Auxiliary equipment	Vessel and piping	Vessel and piping	Vessel and piping

These systems contribute to the overall system energy requirement, however there is potential to recover waste heat from the process.

2.3.1.2 Main product and side streams

The main output of an electrolyser is hydrogen gas, and the annual production amount depends on the installed capacity rating, energy consumption and running hours. Hourly production rate for an exemplary 10 MW electrolyser based on energy consumption of 5.0 kWh/Nm^3 results in 2000 Nm^3/h hydrogen flow. Converted with the density of hydrogen 0.089 kg/m^3 at standard temperature and pressure (STP 0 °C, 1 bar) the mass flow rate is approx. 178 kg/h. Typically, electrolyser manufacturers quote a hydrogen flow and/or mass rate in their specifications and this corresponds to their designed production rate at beginning of life (BOL). The electricity consumption increases over time due to degradation as discussed in previous section, so power demand for the desired quantity of hydrogen will be higher when approaching the electrolyser stacks end of life (EOL).

Oxygen is formed in water splitting as a side stream and the amount of oxygen in the reaction can be estimated based on the molar masses. Based on eqn. 1 in previous section and the molar masses of hydrogen atom (H = 0.001 kg / mol) and oxygen atom (O = 0.016 kg / mol), the reaction yields 8 times more oxygen gas than hydrogen gas. Rough estimate can be approximated so that for every 1 kg of produced hydrogen, 8 kg of oxygen gas is produced. Oxygen can be utilised in several sectors as illustrated in the following figure.

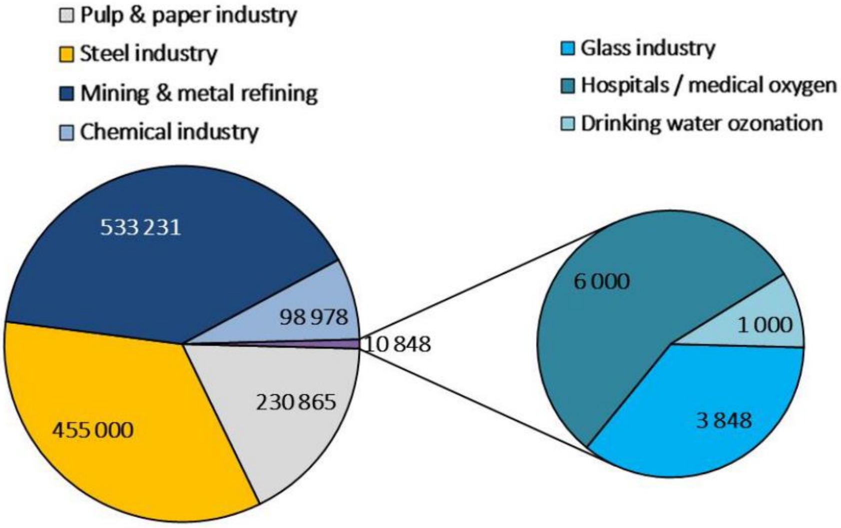


Figure 10. Oxygen use in Finland by sector in tonnes per annum. (Hurskainen 2017, 9)

Waste heat recovery can be utilised especially related to AEL and PEM water electrolysers which require external cooling. The following graph describes the inefficiencies at different load points of a PEM electrolyser resulting from losses occurring in the stack, balance of plant system and power conversion.

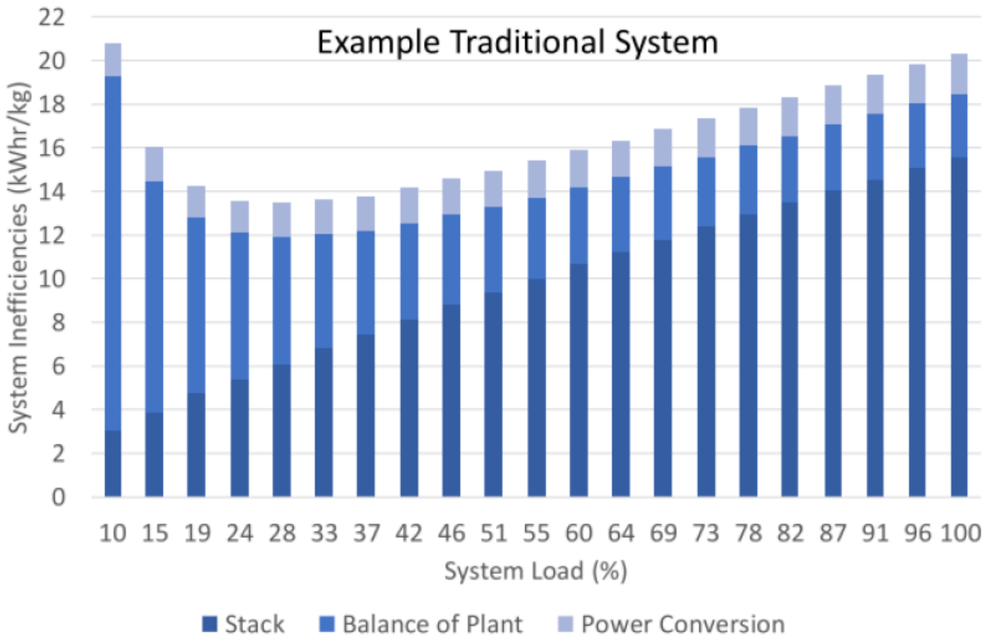


Figure 11. Electrolyser plant system inefficiencies. (Tiktak 2019, 67)

These inefficiencies generate the energy requirement for the PEM electrolyser system which are additional to the overall energy demand for splitting water. Heat recovery could be applied and capture waste heat from the stack and gas streams heat exchangers to increase the electrolyser plant efficiency. An electrolyser system energy flow example is illustrated in the below figure.

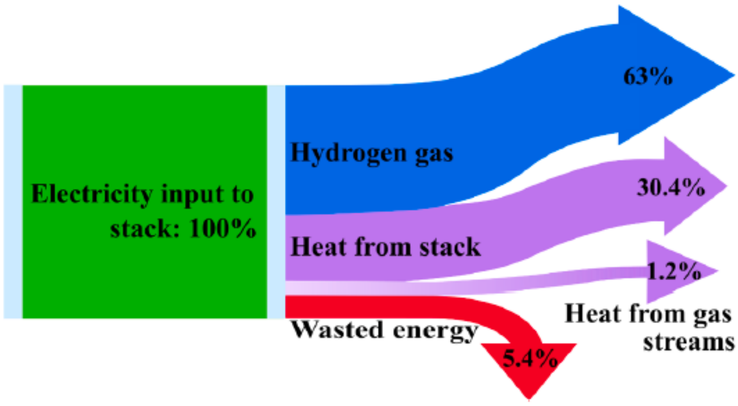


Figure 12. Electrolyser system energy flows. (Burrin et al. 2021, 5)

Theoretically, 31.6 % of the energy input could be recovered and the total energy efficiency could thus reach 94.6 % for an electrolyser plant with heat recovery. Burrin et al. (2021) simulated a 1 MW PEM electrolyser model with heat recovery and according to their study, 312 kW of heat with water temperature of 75 °C and 3933 kg/h flow could be extracted from the system and fed to the district heating system. Over 90 % total efficiency level was observed by Tiktak (2019, 46) in a study of PEM electrolysis heat management. Waste heat recovery could be implemented for both AEL and PEM water electrolysers and when integrated to a district heating network, the increase in the plant efficiency and the possible additional revenues is considerable.

2.3.1.3 Hydrogen storage and transport

Hydrogen can be stored as compressed gas or in liquid form in physical storages. Chemical storage is also an alternative for storing hydrogen. The following figure illustrates the main pathways of hydrogen storages.

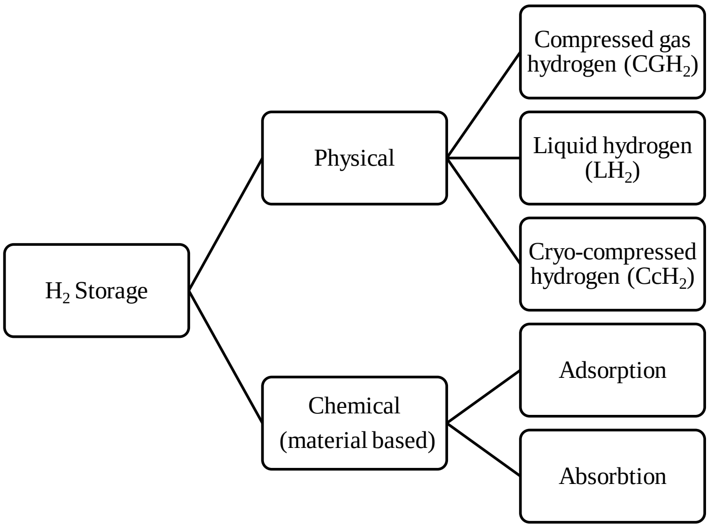


Figure 13. Hydrogen storage alternatives. Modified from (Hassan et al. 2021, 5).

Material based hydrogen storage technologies include adsorption methods which is a process where a molecule of a gas or liquid is transferred to a solid surface. Absorption is a technique used to absorb hydrogen into a material such as metal hydrides. These methods are reversible so hydrogen can be extracted again into use. Reforming hydrogen into fuels or chemicals e.g. ammonia acts as a storage medium as well. (Hassan et al. 2021, 11, 12, 15)

This section considers physical storages, so material-based technologies are not discussed further. Fuel synthesis is discussed in chapter 2.3.3.

Hydrogen becomes liquid at -253 °C, 1 bar and the density increases to 71 kg/m^3 requiring much less storage space than in standard conditions. However, the liquefaction process is very energy intensive. The energy required for the liquefaction process is approx. 35 % of the LHV of hydrogen, resulting in significant increase in energy consumption. Liquefied hydrogen requires special cryogenic storage tanks and are subjected to boil-off losses which can range between 0.3 - 3 % loss of mass per day. Scaling and improving insulation of the storage will reduce losses. Generally, liquefaction is preferred for large storage sizes and longer transportation distances. Cryo-compressed storage aims to get benefits from both cooling near liquefaction temperature and compression of hydrogen resulting in similar volumetric densities as hydrogen in liquid form. Compressing hydrogen increases its volumetric density and increasing to e.g. 700 bar the resulting density is approx. 40 kg/m^3. Further compression can reach similar values than liquefaction, however pressure vessel limits restrict the technical feasibility. (Carriveau, Ting 2016, 7; Hassan et al. 2021, 7; Trattner et al. 2021, 5)

Compressed hydrogen is the common storage type that is used in the industry and the technology is mature and commercially available. CGH_2 storage is typically in pressure vessels which are be categorised as follows (Hassan et al. 2021, 6):

- Type I. Fully metallic. Pressure limit of 500 bar. Low cost.
- Type II. Metallic with carbon fibre wrapping. No pressure limits. Medium cost.
- Type III. Fully composite with metallic liner. Pressure limit of 450 bar. High cost.
- Type IV. Fully composite with polymer liner. Pressure limit of 1000 bar. Very high cost.

Type I and II are mostly utilised in onsite bulk hydrogen storage, typically in bundles of cylinders. The ratio of hydrogen capacity and vessel mass is referred as the gravimetric capacity which is typically used for tank comparison. The gravimetric capacity is the lowest with type I with approx. 1 wt.% and it can increase to over fourfold (> 4 wt.%) with type IV due to weight saving in vessel materials. Compressed hydrogen vessels are subjected to embrittlement issues due to hydrogen molecules entering into materials and causing loss on the material integrity. Fatigue and stress related to applied pressure also plays a role in pressure vessel characteristics. (Hassan et al. 2021, 6)

2.3.1.3.1 Compression of hydrogen

Hydrogen compressors are typically reciprocating type electro-hydraulic driven piston compressors, usually operating in single or multiple stages. Due to the low molar mass of hydrogen and the volumetric compression need, piston compressor is more efficient than e.g. centrifugal compressor (Carriveau, Ting 2016, 18). Power demand for the compressor can be estimated with the following equation (Nexant 2008, 71).

$$P_{comp} = \frac{Z\left(\frac{m_{H_2}}{M_{H_2}}\right)RT\left(\frac{1}{\eta_{is}}\right)\left(\frac{k}{k-1}\right)\left[\left(\frac{P_{out}}{P_{in}}\right)^{\left(\frac{k-1}{nk}\right)} - 1\right]}{3600} \tag{6}$$

Where:

P_{comp}	Compressor power [kW]
Z	Compressibility factor [-]
m_{H_2}	Hydrogen mass flow rate [kg/h]
M_{H_2}	Molar mass of hydrogen [2.016 kg/kmol]
R	Universal gas constant [8.3144 kJ/kmolK]
T	Inlet gas temperature [K]
η_s	Isentropic efficiency [%]
k	Ratio of specific heats [-]
P_{out}	Outlet pressure [bar]
P_{in}	Inlet pressure [bar]
n	Number of stages [-]

The above equation considers an isentropic process which is adiabatic and reversible thus it represents an ideal compressor. The compressibility factor Z is used to correct the ideal gas behaviour to real gas behaviour. Literature values for the mean value of Z is typically approx. 1.03. Specific heat ratio for hydrogen is 1.41. Isentropic efficiency values range from 86 – 92 %. In addition, compressors are typically including inter-coolers and utilising more than one stages if high compression ratios (P_{out}/P_{in}) are used. (Nexant 2008, 69)

Nevertheless, the ideal compressor equation can be used for estimation of compressor design power P_d and energy consumption. Further correction with the electrical motor drive efficiency (η_{el}) can be done as follows.

$$P_d = \frac{P_{comp}}{\eta_{el}} \tag{7}$$

Example for a single stage compressor power estimation with 178 kg/h hydrogen mass flow, inlet temperature and pressure of 25 °C and 30 bar, outlet pressure of 350 bar, isentropic efficiency of 89 % and electric drive efficiency of 95 %, yields a compressor power demand of approx. 266 kW. This results in an energy consumption for hydrogen compression of approx. 1.5 kWh/kg. It must be noted that the compression ratio significantly impacts the compressor power demand P_{comp}, and thus there is a preference for compressed hydrogen output from the electrolyser and multi-stage compressors.

The below figure compares the compression energy need at different pressures and liquefaction energy requirements with associated densities. The previous equations with single stage compression are used to give an example of the compression energy need from 1 bar initial pressure to different compression levels. The volumetric energy content in LHV is also illustrated.

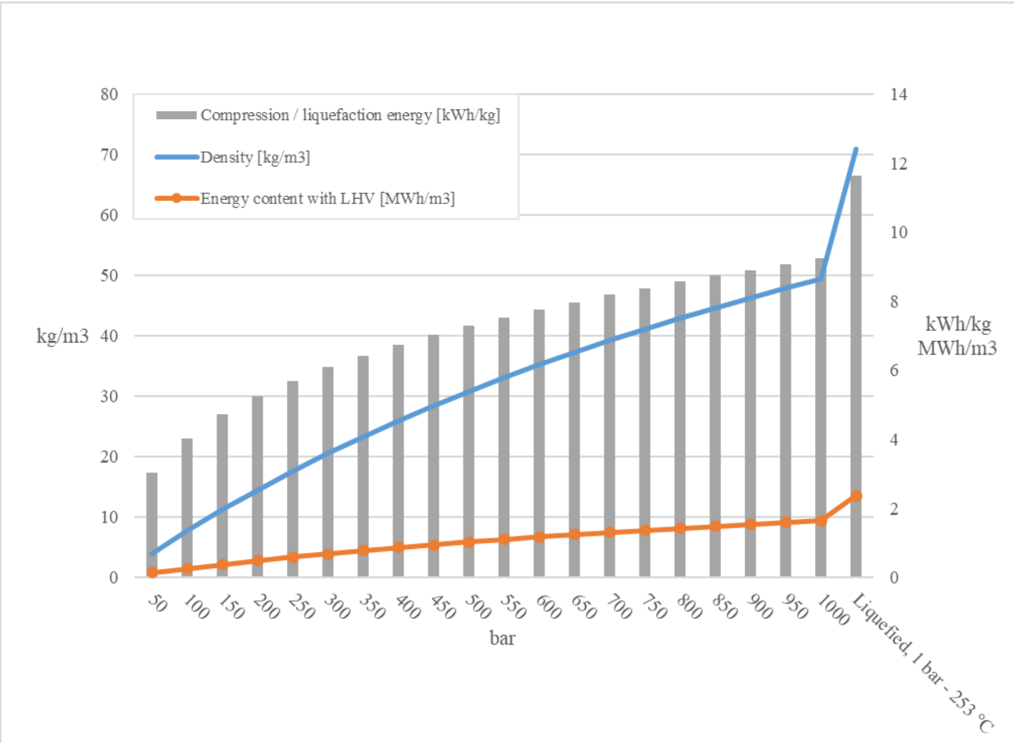


Figure 14. Hydrogen compression energy need at different pressure levels compared with liquefaction and volumetric energy content. Initial pressure level at 1 bar. Isothermal (T = 25 °C) density data from (Lemmon et al. 2021).

As it can be seen, compression can be preferable to liquefaction in terms of energy consumption even at very high compression ratios.

2.3.1.3.2 Delivery methods for hydrogen

Pressure vessels are transported on roads via tube trailers and preferably in the lighter type composite vessels. Due to low gravimetric storage capacity of hydrogen pressure vessels, the actual amount of compressed hydrogen that can be transported via trailer is ranging from

600 kg up to 1500 kg, depending on storage pressure and trailer design (Baldwin 2013, 2,3). Over 1 ton trailer capacities are on development stage, with current maximum of 890 kg (Baldwin 2017, 30). The example capacities are from Hexagon Lincoln which utilise type IV composite pressure vessels in their trailers, which have achieved quite high gravimetric storage capacities such as 7 wt. % as in the example given in figure below.

Figure 15. Titan CGH_2 tube trailer with 616 kg total hydrogen capacity at 250 bar. Pressure vessel outer diameter 1087 mm, length 11.67 m and weight 2175 kg. (Baldwin 2017, 9, 12)

Urban area hydrogen pipeline transportation isn´t widely used as hydrogen infrastructure is in its infancy, however natural gas pipelines have been used for decades around the world. Consequently, the experience gained in natural gas pipelines are adopted to hydrogen pipeline development. Pipe material selection and general construction (welding, leak testing) requires more attention due to hydrogen properties. Installation location and rights of way along with safety considerations are affecting the feasibility of hydrogen pipeline construction. Delivery pressure can be lower in the pipeline (< 100 bar), however compression is needed at the supply and delivery site, depending on final hydrogen use and pipe overall length. (Witkowski et al. 2017, 2)

Ultimately, the yield of hydrogen production and transportation distance determines the cost and benefit of the pipeline alternative. If the transport distance is less than 100 km from production site and hydrogen use within the area is low (< 400 kg/day, fuel cell electric vehicle refuelling), transportation via tube trailer can be seen as a more attractive solution. Naturally, if the volumes are larger, pipeline delivery is the preferred alternative. (Nexant 2008, 17)

There are two existing hydrogen pipeline networks in operation in Germany. One is in western Germany and is owned by Air Liquide. The pipeline diameters are varying from 100 – 300 mm with operating pressures of 15 – 25 bar. The total length is approx. 220 km. The other network which has operating pressures of 20 – 25 bar and 100 km length is in eastern Germany and it is owned by Linde. These networks serve 30 hydrogen fuelling stations from which seven are open for public. (Baufumé et al. 2013, 5)

A notable initiative set by 23 gas infrastructure companies from 21 different countries is the vision of a European Hydrogen Backbone. The pan-European hydrogen transmission infrastructure would be expanded stepwise from an emerging infrastructure network of connected industrial clusters by 2030 and further increasing the transmission network by 2035. A mature hydrogen backbone network would comprise of new hydrogen pipelines and repurposed natural gas pipelines with a total length of 39700 km by 2040. The transmission pipeline diameters would range from 500 – 1200 mm which would accommodate the GW scale hydrogen transmission. The below figure illustrates what the network would look like in Finland for the mature transmission network scenario. (Jaro et al. 2021, 3, 6, 8, 17)

Figure 16. The Finnish hydrogen transmission network in the European Hydrogen Backbone. (Jaro et al. 2021, 23)

The realisation of the ambitious vision requires significant regional efforts for distribution network development which should be considered in any large-scale hydrogen projects.

2.3.2 CO_2 capture from a waste-to-energy plant

Carbon capture is a process where carbon dioxide is captured from the atmosphere or different point sources to mitigate CO_2 emissions. The carbon captured is either stored (CCS), utilised (CCU), or it can be a combination of both utilisation and storage (CCUS).

The designation of the CO_2 source can be categorised as green or black. Green carbon refers to biogenic or atmospheric CO_2 separation, an example of the former being separation from biogas process and the latter being separation from ambient air via direct air capture. Black carbon is the result from CO_2 separation from flue gases emitted from fossil-fuel combusting power plants or from the production of steel and cement. (Sterner, Stadler 2019, 41)

The source of the CO_2 determines the environmental effect of further utilising CO_2 as a feedstock for products and its benefit on decarbonisation efforts. Fossil-fuel point source CCS would reduce the emissions from the sector but would not significantly contribute to CO_2 emission reduction with CCU as the utilised carbon will be eventually emitted if processed to e.g. synthetic fuels (Fasihi et al. 2019, 18). Therefore, utilising biogenic sources for CCU would be preferred.

Waste-to-energy (WtE) plants are considered as an unavoidable CO_2 source and it is an efficient and ecological method to handle waste as opposed to landfills which release methane uncontrollably (Fasihi et al. 2019, 18; Wienchol et al. 2020, 3). WtE combined heat and power plant (CHP) incinerates a varying type of municipal solid waste (MSW), and the composition is naturally variable. The typical composition of global waste is presented in the following figure.

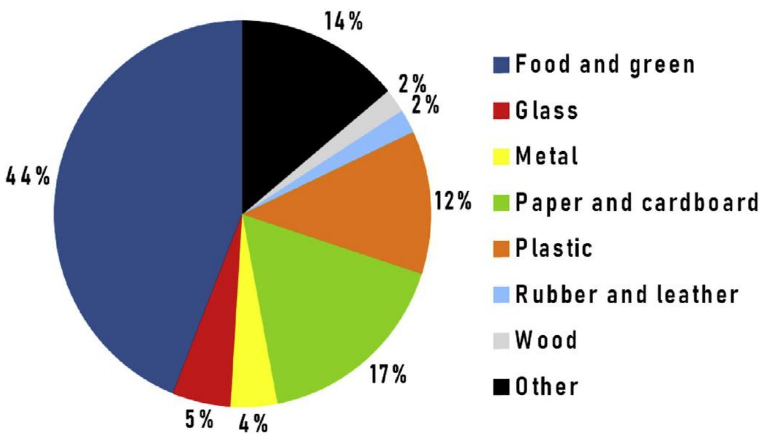


Figure 17. Waste composition globally. (Wienchol et al. 2020, 3)

The biogenic share of global waste is over 50 %, however this can vary significantly. The share of renewable energy content in MSW in Europe is in the range of 55 % (± 9 %) and in Finland it is estimated to be around 57 %. Generating energy from waste results in lower GHG emissions than e.g. coal or peat, with waste incineration having 50 % renewable content the GHG impact is 40 kgCO2eq/GJ, for coal 98-108 kgCO2eq/GJ and for peat 97-106 kgCO2eq/GJ. These estimated values are typically based on statistical methods and renewable sources in waste means organic (food & green) waste together with paper, cardboard, and wood. A detailed composition study in Finland resulted in average share of renewable energy content of 30 % due to low biowaste share and higher plastics share in waste which emphasizes the variance of waste composition. (Horttanainen et al. 2013, 2, 6)

Utilising carbon capture in WtE plants would further curtail their environmental impact from flue gases. A typical WtE plant comprises of a grate incinerator from which the hot flue gases heat up the boiler water forming steam for the steam turbine and district heating systems. Exhaust gases are treated in a separate section for reducing nitrous and sulphur oxide emissions as well as other impurities such as heavy metals and acidic compounds. Combustion process CCS technologies include post-combustion, pre-combustion, chemical looping and oxy-fuel combustion. Post-combustion CCS technology with chemical absorption in a monoethanolamine (MEA) based aqueous solution is the most mature technology and can be applied as a retrofit to existing plants. Oxy-fuel technology could be considered especially if an electrolyser plant with high oxygen side stream generation is located onsite, however this technology has not received sufficient research efforts namely in the oxy-fuel combustion of MSW. (Bailera et al. 2020, 49, 55; Magnanelli et al. 2021, 2; Wienchol et al. 2020, 5)

Thus, the CCS pathway that could be applied today for a WtE plant would be post-combustion CO_2 capture technology. The main drawback of the MEA based CO_2 absorption technology is the high energy consumption of the process. The amine solvent regeneration requires most of the energy which is supplied as steam to the process and the typical energy requirement ranges from 3.6 – 4 GJ/t_{CO2} for 30 % wt. MEA solution and 90 % CO_2 capture efficiency. Novel solvents can reduce the energy requirement to e.g. 2.6 GJ/t_{CO2} and 2.3 GJ/t_{CO2} which represents the heat duties of Mitsubishi Heavy Industries and Shell licensed solvents respectively. (Bailera et al. 2020, 25; IEAGHG 2020, 66)

If the heat is taken up from the CHP plant steam generation cycle, the energy penalty can result in losses in the production of electricity and district heating. Magnanelli et al. studied the steam extraction from different parts of the WtE plant with approx. 84 % capture efficiency and approx. 125 kt of captured CO_2, which resulted in production losses for district heating and electricity of 6.4 % and 30.3 % respectively for steam extraction from the boiler drum. When steam was extracted from the steam turbine the energy penalty was 8.2 % for heat and 12.2 % for electricity. Alternatively the heat can be generated externally. If the plant is contractually obligated to deliver heat, considerations should be made on the energy extraction for the solvent regeneration process. (Magnanelli et al. 2021, 8, 9)

2.3.2.1 Main product and side streams

The captured carbon dioxide can be considered as a resource with CCU applications. Numerous industries can utilise CO_2 as a feedstock for further production into useful products. The figure below illustrates the range of possible CCU applications.

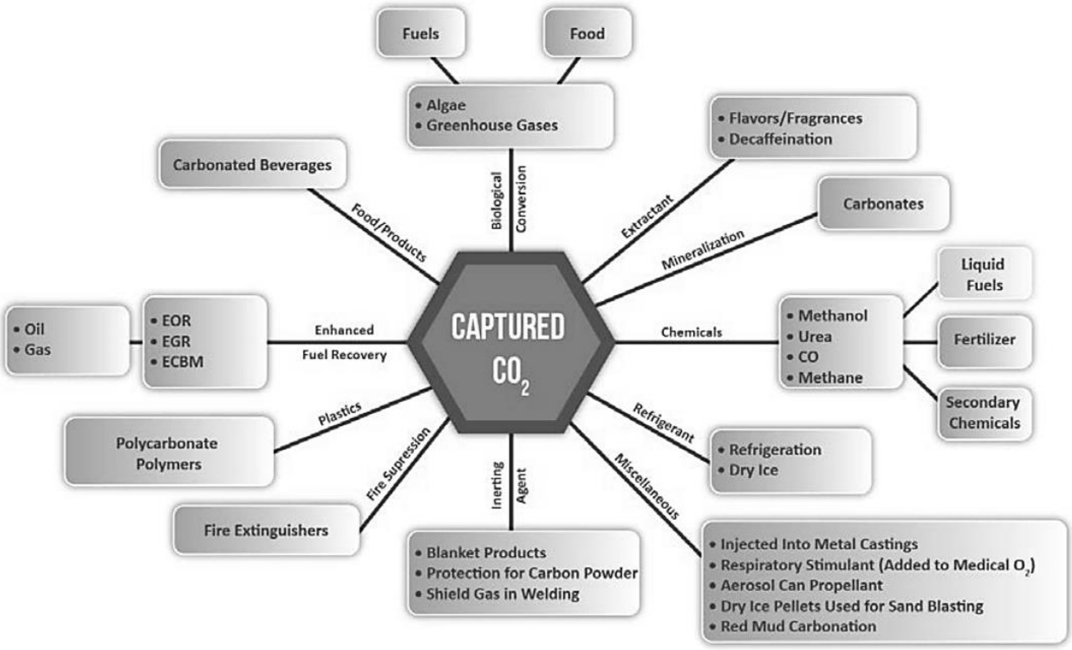


Figure 18. CO_2 utilisation pathways. Enhanced oil recovery (EOR). Enhanced gas recovery (EGR). Enhanced coalbed methane recovery (ECBM). (Kapetaki 2020, 13)

The annual global consumption of CO_2 was estimated to be approx. 250 Mt in 2020 of which the majority of approx. 57 % is used by the fertilizer industry for urea production. Oil and gas industry is the second largest consumer at approx. 34 % share where CO_2 is utilised in

EOR. The food and beverage industry consumes each approx. 3 % of the global demand, while the rest is used in metal fabrication, fire suppression, cooling and in greenhouses for plant growth stimulation. Novel CO_2 conversion pathways are expected to emerge in the coming years such as synthetic fuel production, plastics, chemicals and building materials. (IEA 2019, 6, 7)

There are currently a few WtE plants globally that have installed or have plans on the application of carbon capture technology. Majority of the projects have directed the use of CO_2 into greenhouses for plant growth acceleration and these projects are primarily based in the Netherlands. A project in Norway has the ambition to store the captured carbon permanently in a geological storage in the North Sea. The following table summarises the WtE plants with CCUS operations.

Table 4. WtE plants with carbon capture. (IEAGHG 2020, 158)

WtE plant	**Country**	**CO_2 produced [kt/a]**	**CO_2 captured [kt/a]**	**CO_2 capture technology**	**End use of CO_2**	**Status**
HVC Alkmaar, Project 1	NL	~ 674	4	Amine	LCO_2 greenhouse horticulture	Ongoing
Fortum Klemetsrud	NO	430-460	414	Shell Cansolv (Amine)	LCO_2 permanent storage in the North Sea	Pilot plant ongoing since 2019. FEED ongoing for full scale plant.
Saga City	JP	54	2.5	Amine	CCO_2 algae cultivation	In operation since 2016
AVR Duiven	NL	400	50-60	Amine (MEA)	LCO_2 greenhouse horticulture	Plant start-up
AEB Amsterdam	NL	~ 1268	450	Amine (MEA)	Determined by the feasibility study	Feasibility study
AVR Rozenburg	NL	~ 1153	800	Based on FEED results	Based on FEED results	FEED study ongoing
Twence Hengelo	NL	~ 600	100	Aker solutions (Amine)	LCO_2 for greenhouses / Formic acid / CO_2 mineralisation	Engineering study for a full-scale project
HVC Alkmaar, Project 2	NL	~ 674	75	Amine	LCO_2 greenhouse horticulture	Feasibility study

Note. Netherlands (NL). Norway (NO). Japan (JP). Liquefied carbon dioxide (LCO_2). Compressed carbon dioxide (CCO_2). Front end engineering design (FEED).

2.3.2.1.1 Reclaimer waste

A notable side stream of the post-combustion carbon capture process with MEA solvent is the waste that is generated in the process. In a typical amine-based carbon capture process, the cooled (40 – 70 °C, 1 bar) flue gas stream is fed into the absorber column where the CO_2 is absorbed in the lean aqueous amine solution and the CO_2 rich solution then exits the absorber column from the bottom. The rich solvent is then fed through a heat exchanger where it is preheated before entering the stripper column. The CO_2 is released in the stripper which operates at a higher (100 – 150 °C, 1 bar) temperature after which the CO_2 gas is dehydrated and compressed for transportation or use. The hot lean amine solution is then recirculated back to the absorption process through the heat exchanger. Before the heat exchanger, a slip stream of the lean amine solvent is sent to a reclaimer where it is purified of contaminants and the reclaimed solvent is fed back to the process. The amine solvent degrades so it cannot be completely recovered, thus a waste stream is generated in the reclaimer and the sludge is discharged from the bottom of the reclaimer. A typical amine process is illustrated in the figure below. (Sexton et al. 2014, 2; Wang et al. 2015, 2)

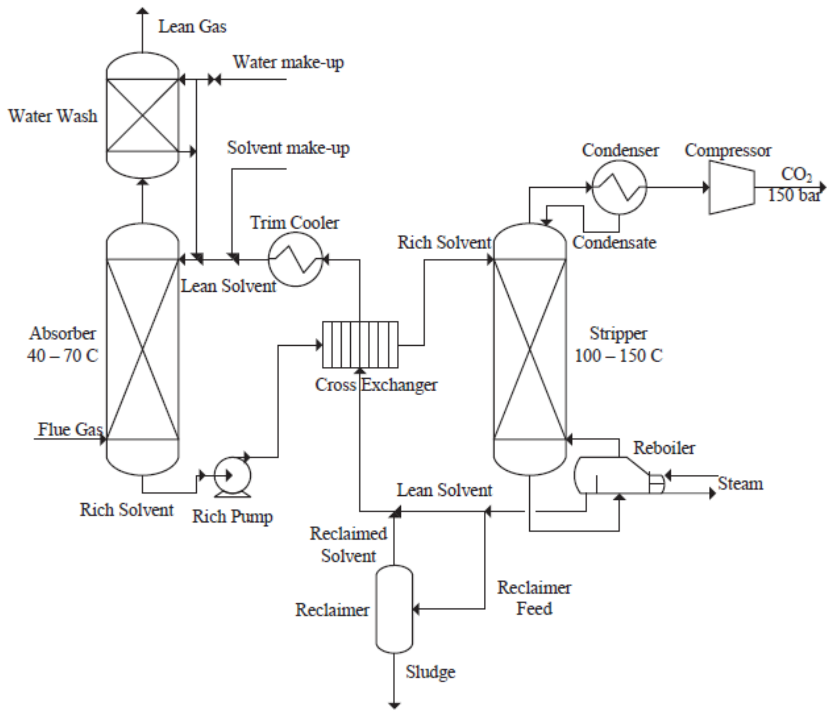


Figure 19. Typical MEA based post-combustion carbon capture process flow. (Sexton et al. 2014, 2)

Conventional thermal reclaiming technology is an energy intensive process where the reclaimer unit can consume approx. 10 % of the total heat demand. The amount of reclaimer waste depends on the slip stream quantity, however it is estimated that 4 – 15 kg of reclaimer sludge is generated per tonne of captured CO_2. The reclaimer sludge has the viscous liquid properties of crude oil and it contains some of the amine solvent and its degradations products together with other captured matter from the flue gas and corrosion products. The reclaimer waste is classified under EU regulations and the European List of Wastes as hazardous according to “07 01 wastes from the manufacture, formulation, supply and use (MFSU) of basic organic chemicals” and “07 01 08* other still bottoms and reaction residues”. (EC 2018a, 35; Wang et al. 2015, 8)

The alternatives for disposing hazardous reclaimer waste are either transportation to a hazardous waste landfill or combustion in a hazardous waste incinerator. However, Sexton et al. (2014, 11) noted that due to the organic carbon and corrosivity content of the reclaimer waste, it is unsuitable for hazardous waste landfill disposal in the EU. The remaining option is then a hazardous waste incinerator where incineration temperature must be increased to at least 1100 °C for 2 seconds as opposed to non-hazardous incineration where minimum temperature and duration requirement is 850 °C and 2 seconds according to national legislation for waste incineration (Finlex 2013, 9 §). This would require waste transportation from a conventional incineration site to a hazardous waste incinerator location or investments in existing facilities.

Ion exchange and electrodialysis are alternative reclaiming technologies where the disposed reclaimer waste can be classified as a non-hazardous aqueous waste stream if no harmful substances such as metals are present in the stream. The aqueous waste stream can be treated in an onsite wastewater treatment plant. However, both technologies have very little proven results in post-combustion carbon capture. (Sexton et al. 2014, 11; Wang et al. 2015, 9, 10)

2.3.2.2 Storage and transport

The permanent storage alternatives for the captured CO_2 are mainly consisting of geological storage methods where the CO_2 is injected deep underground where it is prevented from escaping back to the atmosphere. The geological reservoirs which have the largest storage capacities are depleted oil and gas fields and saline aquifers. Enhanced fuel recovery methods, as depicted in Figure 18, is another way of storing CO_2 in reservoirs. The CO_2 is compressed to increase its density and to liquefy it and injected to depths reaching beyond 800 m to maintain CO_2 in a liquid state. (IEA 2020a, 112)

The possibility of implementing geological storage of CO_2 in Finland has been studied by the Geological Survey of Finland (GTK). The conclusion was that there are no significant geological formations to store CO_2 since there are no hydrocarbon reservoirs in Finland and the compact sedimentary bedrock formations do not indicate the presence of saline aquifers. The geological formation characteristics and depths for storage in the Finnish sedimentary rock and seabed areas remained unfeasible due to lack of geological data. (Aatos et al. 2011, 189, 190)

Another permanent storage alternative that has been studied is the mineral carbonation of CO_2. It is a process where carbon dioxide is converted into magnesium carbonate ($MgCO_3$) or calcium carbonate ($CaCO_3$, i.e. limestone) with chemical reactions of magnesium oxide (MgO) and calcium oxide (CaO). These alkaline-earth oxides are naturally occurring in serpentine and olivine silicate rocks. In addition, metal oxides for carbonation can be found in industrial waste i.e. steelmaking slags and ashes. Mineral carbonation is a very slow natural process and thus must be accelerated when considering CO_2 storage on an industrial scale. This leads to significant energy demands, which can represent 30 – 50 % of the output of a power plant which in turn increases the costs of the process. The process requires silicate materials of approx. 1.6 – 3.7 t/tCO_2 which leads to a significant mining activity with consequent environmental impact. The sustainable alternative is to utilise mineral processing wastes and by-products from mineral production and metal industry. (Aatos et al. 2011, 191; Metz et al. 2005, 51, 52)

Since the geological storage options are not readily available Finland, the captured CO_2 must be transported elsewhere. Pipeline transportation of CO_2 is a mature technology and in liquid phase, it is more efficient than gaseous CO_2 pipeline transport due to its low density. Before transportation CO_2 is typically cooled below its critical temperature (31 °C) and compressed above its critical pressure which is 73.8 bar after which it becomes liquid and the density increases significantly from the density of 1.98 kg/m^3 at STP. Typical pipeline operating pressures range from approx. 86 – 150 bar and the resulting density range is approx. 800 – 1000 kg/m^3 depending on operating temperatures. Onshore pipeline depths are typically 1 m below ground. (McCoy, Rubin 2008, 2; Wilberforce et al. 2021, 6)

The nearest suitable geological formations for CO_2 storage are in Norway. The latest project which is aimed to store 1.5 $MtCO_2$ per year in a saline aquifer in the North Sea basin is the Northern Lights which is part of the Norwegian governments full scale CCS project called Longship and targets to start operations by mid-2024. The requirements for shipping the LCO_2 to the site state that the cargo conditions should meet the specifications of 13-15 bar pressure and -30.5 °C and -26.5 °C with densities below 1100 kg/m^3. This is due to commercial availability and experience from ships carrying cryogenic gases i.e. liquefied natural gas (LNG) tankers. In addition, a conditioning plant and a buffer storage tank is needed at the shore terminal for the shipping transport alternative. Liquefaction is done at the conditioning plant and LCO_2 is then transferred to the cryogenic buffer storage. Storage tanks for LCO_2 are typically made from carbon steel with polyurethane insulation and includes a refrigeration unit. The conditioning plant should be located at the capture site to ensure that the LCO_2 properties are not deviating along the transportation chain. Although the Northern Lights project is initially set up for Norwegian CCS activities, they encourage cross border deliveries for increasing decarbonisation efforts in the EU. (Air Products 2014; Bjerketvedt et al. 2022, 2, 3; Northern Lights 2022; Wilberforce et al. 2021, 6)

2.3.3 Fuel synthesis

Fuel synthesis can act as the chemical storage for hydrogen; however it does not count as a CO_2 storage since it will be eventually emitted after fuel combustion. While hydrogen has a high gravimetric energy content of 120 MJ/kg which is approx. threefold higher than diesel and gasoline, its volumetric energy density is low due to being a very light gas. By synthesizing hydrogen to other fuels, the stored energy capacity can be increased as the volumetric energy density defines the space required for fuel storage. Below figure illustrates the differences in volumetric and gravimetric densities of hydrogen versus other fuels.

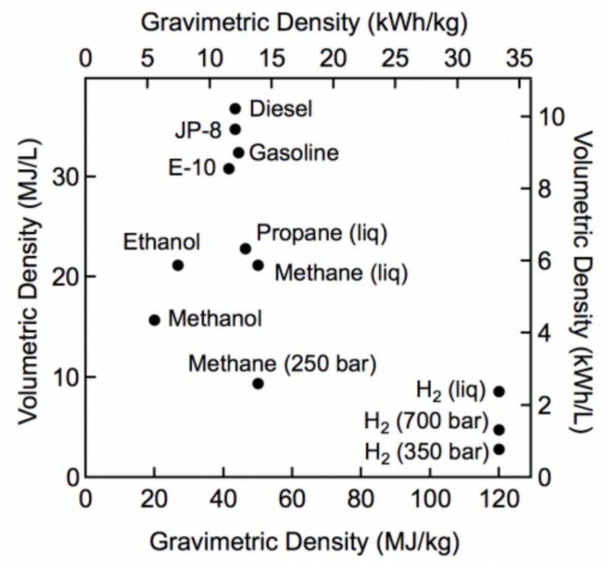


Figure 20. Gravimetric and volumetric density comparison for different fuels and hydrogen based on LHV. (Pistidda 2021, 3)

There are several pathways to convert hydrogen from water electrolysis into different electrofuels (e-fuels). The following figure illustrates different fuel conversion pathways.

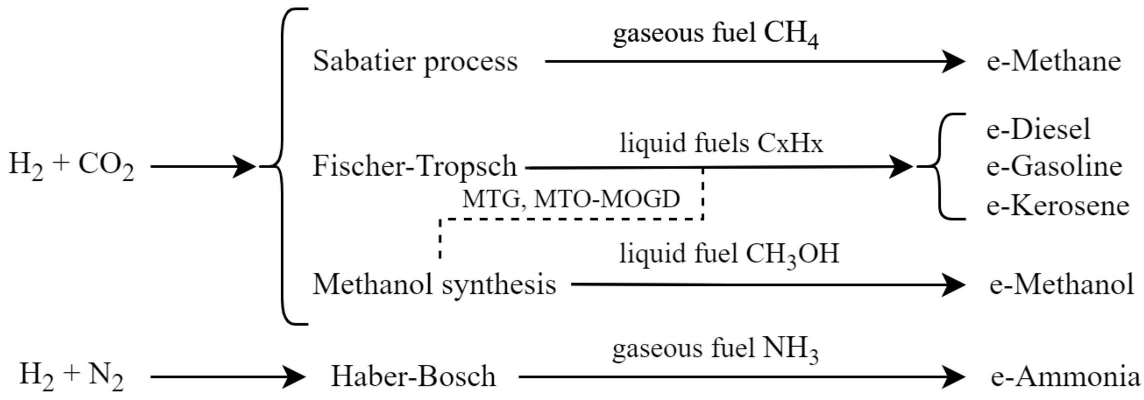


Figure 21. Different fuel synthesis pathways. Methanol-to-gasoline (MTG). Methanol-to-olefins-Mobil´s olefins to gasolines and distillates (MTO-MOGD).

Power-to-liquid (PtL) fuels which could replace the conventional fossil-based fuels have the potential to serve as drop-in fuels as the infrastructure currently exists and the process route allows the production of different fractions. Methanol can be used in e.g. combustion engines with relatively small modifications or by further upgrading it to conventional fuels. Synthetic kerosene could potentially bring significant GHG reductions in the aviation sector with estimates of at least 70 % savings compared to conventional jet fuel. In addition, synthetic liquid fuels are cleaner in combustion, containing no sulphur and reducing particle and nitrous oxide emissions, carbon monoxide and other hydrocarbon emissions. (Dieterich et al. 2020, 6, 7; Schmidt et al. 2018, 8)

Most of the synthesis products are hydrocarbon-based fuels, except ammonia which is the only carbon free fuel which requires nitrogen that can be separated from air. Ammonia is typically used by the chemical industry for fertilizer production and it is a relatively new fuel source. The toxic nature of ammonia could potentially pose a health hazard if it is released into the atmosphere in high concentrations and direct exposure should be avoided. However, it has the potential to be a carbon free fuel that can be used in fuel cells and in combustion engines with ignition aid from pilot fuel. Development and testing are ongoing for ammonia burning engines for the marine sector by e.g. Wärtsilä. (Hansson et al. 2020, 3; Wärtsilä 2021b)

2.3.3.1 Methanation

The focus on fuel synthesis in this study will be on methanation since it has shown the most potential for hydrogen and carbon dioxide conversion in Vaasa region as discussed in chapter 5.1. In addition, methanation offers the lowest production costs compared to other synthesis pathways as discussed by Brynolf et al. (2018, 10). There are two types of methanation routes: biological and catalytic.

Biological methanation route involves single cell methanogenic archaea microbes that produce methane by metabolizing CO_2 and H_2 for growth energy. These microbes act as the biological catalyst for methane formation. Biological methanation is typically operated at temperatures ranging from 20 – 70 °C and pressures of 1 – 10 bar. The limiting factor for industrial scalability is the low reaction rate[3] which in turn means that large reactor volumes are required for production of high quantities of methane. In addition, the methane content of the produced gas can have varying values of 5 – 98 % depending on reactor type. Low methane content should be upgraded to match the quality requirements of the gas network if injected to the grid. Advantages of the biological route are that the process is very tolerant

[3] Reaction rate is the gas hourly space velocity (GHSV, h^{-1}) of the reactor. GSHV is the ratio of volumetric flowrate of the feed gas at STP and the reactor volume. Biological reactors typically have a GHSV of < 1 h^{-1} while commercial catalytic reactors can reach 2000 – 5000 h^{-1} for similar methane content. (Götz et al. 2016, 4, 9)

for impurities in CO_2 feed gas and can have flexible loading ranges from 0 – 100 %. The first MW (electrolyser rating) scale project for biological methanation has been materialized in Denmark by Electroachea's BioCat project which produces 50 Nm^3/h of grid quality methane. (Bailera et al. 2020, 68, 69; Electrochaea 2022)

In catalytic methanation, the catalyst for methane formation is an active material, typically nickel based. In contrast to biological methanation, the catalytic process parameters are higher with temperature ranges of 250 – 550 °C and pressures of 1 – 100 bar. Elevated operating temperatures correlate to significantly higher reaction rates than biological reactors which can be several orders of magnitudes higher on a commercial fixed bed catalytic methanation reactor with multiple reactors in series and thus total reactor volumes can be smaller, requiring less space and saving investment costs. Higher operating temperatures allow waste heat integration as well which in turn requires proper heat management system. Catalytic methanation reactors have low tolerances on CO_2 feed impurities and have a loading range of 20 – 100 % which is limiting transient operations. The methane content from catalytic methanation reactors is typically > 90 %. The largest existing power-to-methane (PtM) plant which utilises fixed bed catalytic methanation and three 2 MW alkaline electrolysers to produce approx. 1000 t / a of synthetic natural gas (SNG) is the Audi e-gas plant which was developed by Etogas in Germany and has been in operation since 2013. (Bailera et al. 2020, 69; Götz et al. 2016, 5, 9, 13; Sterner, Specht 2021, 13)

In Finland, the network gas quality is defined by Gasgrid Finland, and they specify the methane content which is 95 – 98 % for refined biogas and 85 – 98 % for natural gas. (Gasgrid Finland 2022a) Considering the technical maturity and space requirements together with heat integration possibilities, it makes the catalytic alternative a suitable choice for methanation in conjunction with a CHP plant CO_2 capture.

2.3.3.2 Main product and side streams

Methane is produced in a Sabatier reaction with a hydrogen and carbon dioxide ratio of 4:1. The reaction is defined in the equation below. (Gray et al. 2022, 4)

$$\mathrm{CO_2} + 4\mathrm{H_2} \xrightarrow{\text{yields}} \mathrm{CH_4} + 2\mathrm{H_2O} \qquad \Delta H = -165\ \mathrm{kJ/mol} \tag{8}$$

As ΔH is < 0 the reaction is exothermic and thus heat is released from the process.

The mass balances of a PtM system can be calculated based on the molar masses of the reactants and products. The following table summarizes the molar masses.

Table 5. Molar masses for PtM. (Gray et al. 2022, 9)

Reactants/Products	Molar mass [g/mol, kg/kmol]
CO_2	44.009
H_2	2.016
CH_4	16.043
H_20	18.015
O_2	31.998
CO_2	44.009

By utilising eqn. (8) and eqn. (1), a mass balance example for a PtM process for producing 1000 t of SNG per year is illustrated in the following figure.

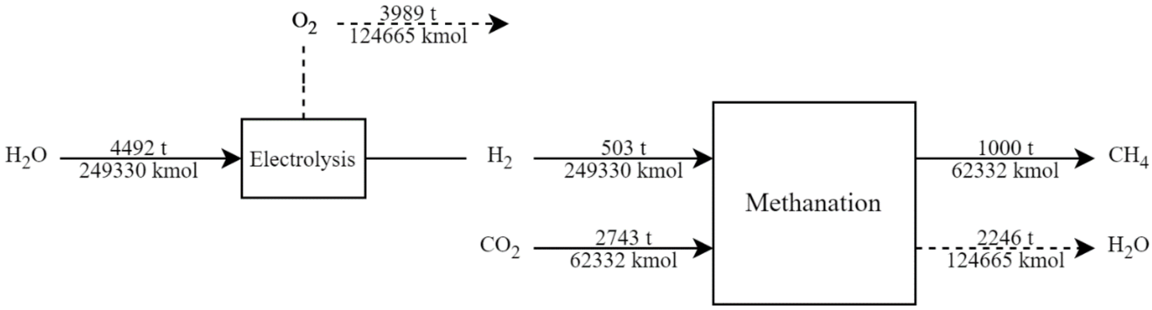


Figure 22. Stoichiometric mass balances for power-to-methane process.

The reaction assumes 100 % CO_2 conversion which is unlikely due to efficiency losses in the process. For a methane content of > 90 %, the CO2 conversion efficacy is approx. 98 % (Götz et al. 2016, 4). The methanation chemical efficiency on energy basis for 100 % conversion can be calculated using eqn. (9) and the HHV (or LHV) of hydrogen 142 MJ/kg (120 MJ/kg) and methane 55.5 MJ/kg (50 MJ/kg) (Gorre et al. 2020, 2).

$$\eta_{methanation,HHV\,(or\ LHV)} = \frac{HHV_{CH_4}\left(or\ LHV_{CH_4}\right) \times m_{CH_4}}{HHV_{H_2}\left(or\ LHV_{H_2}\right) \times m_{H_2}} \qquad (9)$$

Using the mass flows from above example for hydrogen (m_{H_2}) and methane (m_{CH_4}), the resulting chemical conversion efficiency is approx. 78 % based on HHV (83 %, LHV). This is the theoretical maximum efficiency which reduces when considering the auxiliary power needs such as pumps and compressors i.e. BoP equipment. (Gorre et al. 2020, 5) PtM chain (electrolysis and methanation) efficiency is around 55 % when considering 70 % efficiency (HHV) of the electrolyser and not considering the heat integration possibilities. The chain efficiency is affected by the auxiliary power needs of the complete plant and if heat is utilised. Thema et al. (2019, 8) analysed dozens of methanation projects and found out that the mean PtM efficiency was only 41 % which was due to that most of the projects did not utilise waste heat.

A notable side stream from the methanation process is that the reaction yields significant amounts of water which is separated from the process. This could be recirculated to the water electrolysis process where it would reduce water consumption. In the above example, the water generated from the methanation process is 50 % of the water feed for the electrolysis process.

The high temperature heat generated by the catalytic methanation process could be used as input for steam generation to use in a SOEC electrolyser. Alternatively, the waste heat could be used to cover the heating requirements for the CO_2 capture process. Below figure illustrates the heat management system for the Audi e-gas plant.

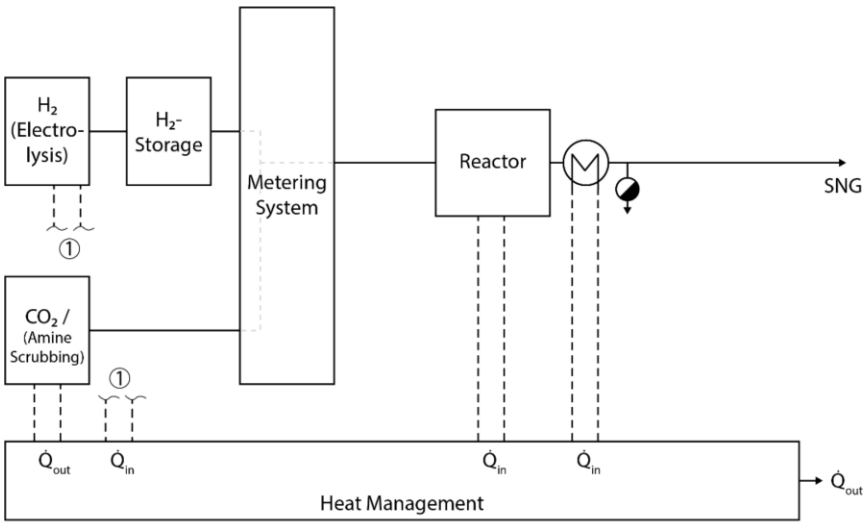


Figure 23. Heat management system of the Audi e-gas 6 MW PtM plant. (Sterner, Specht 2021, 12)

The Audi plant uses the high temperature heat from a molten salt-cooled tube bundle methanation reactor for the amine scrubbing process for CO_2 separation from a nearby biogas plant. Electrolysis heat is also collected, and the low temperature heat is utilised in the biogas facility as well. The plant is equipped with a 10-bar buffer storage for hydrogen of approx. 1 hour (1200 m^3, STP) duration for allowing continuous methanation process and thus a more dynamic operation of the whole plant. (van Basshuysen 2016, 158, 159)

2.3.3.3 Storage and transport

After methanation, the SNG is cooled, dried and purified via membrane if necessary to meet the grid requirements. After gas preparation, the gas is compressed to be delivered to the grid or to a storage tank. (Frank et al. 2018, 8)

The storage tanks for compressed SNG are similar pressure vessel types I – IV as discussed in the chapter 2.3.1.3 since hydrogen infrastructure development is derived from existing natural gas industry. Type I pressure vessels are the predominant choice globally for above ground stationary storage and filling stations for compressed natural gas for their wide pressure rating and low investment costs. Road traffic compressed natural gas (CNG) storage pressurisation is typically in the range of 200 – 250 bar. Lighter type III and IV tanks can be applied for fast filling stations or mobile transportation storage vessels. (FIBA 2018; van Basshuysen 2016, 355)

Liquefied natural gas (LNG) is widely used in long distance sea transportation and bulk cryogenic storage containment in LNG terminals from where it's vaporised and pressurised for distribution. Methane liquefies at temperature of -162 °C in ambient pressure which increases its density to approx. 600-fold from its ambient state of 0.7175 kg/m^3 to 421 kg/m^3. LNG storage also suffers from boil-off losses. The liquefaction process energy requirement is approx. 6 – 11 % of the gas energy content. Liquefying SNG would thus be slightly less energy intensive than hydrogen, however it would be applicable for longer transport distances or when onboard storage on e.g. LNG fuelled ships are needed. (van Basshuysen 2016, 55, 56, 83)

Pipeline transportation of natural gas in Finland is handled by the gas network operator Gasgrid Finland and the national pipeline infrastructure is illustrated in the following figure.

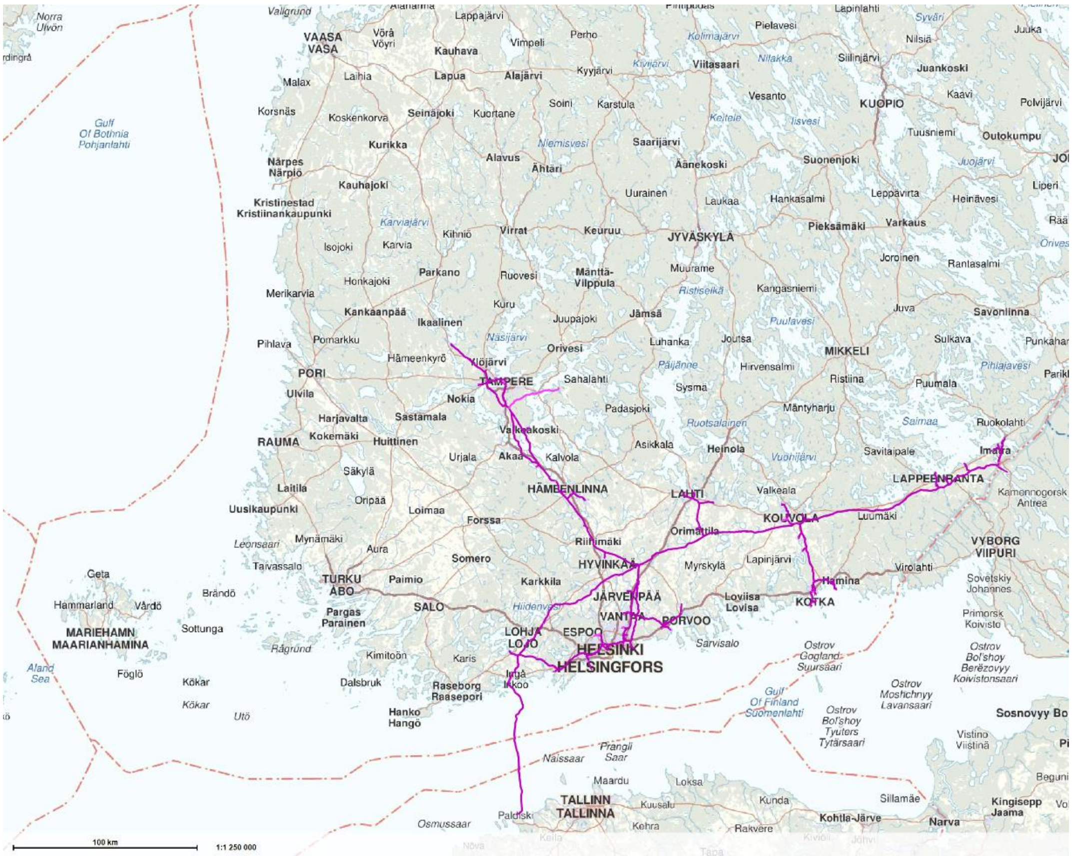


Figure 24. Gas transmission network in Finland. (Gasgrid Finland 2022b)

The natural gas is fed to the transmission network from Russia and Estonia via compressor stations. In addition, local biogas plants supply the network with biomethane. The pipeline network comprises of high pressure transmission lines of 1150 km and low pressure distribution lines of 60 km. Pipeline diameters are varying from DN100 – DN1000, where the smaller diameters are for distribution lines to consumers. (Gasgrid Finland 2022c)

As it can be seen from the gas network map, the transmission network does not reach Vaasa, so injecting SNG to the national grid might not be feasible without large scale infrastructure development. Regardless, further development of distribution and transmission lines are essential if green hydrogen and the SNG derived from it is intended play a larger role in the national gas supply scheme.

3 Regulatory considerations for PtX ecosystem

This chapter will describe the regulative aspects concerning the PtX process and its products. First an overview of the European regulations will be presented followed by the national level regulations.

3.1 European regulations

The European Union sets a variety of different legislative acts among its member countries, some of which are binding, and some are for guidance or setting specific goals (EU 2022a). The following table summarizes the different legislation types.

Table 6. Different types of EU legislations. (EU 2022a; EU 2022b; EU 2022c)

EU legislation type	**Legislative force**	**Description**
Regulations	Binding act	Must be applied in its entirety in EU Member States
Directives	Binding objective	Sets objectives to be achieved in Member States. It is up to the Member States to choose the methods on how to reach the objectives.
Decisions	Binding to specific groups	Decisions are made specifically to an EU country or a company and are binding towards them.
Recommendations	Non-binding acts	Can provide guidance to interpretation or content of EU law.
Opinions	Non-binding acts	The main EU institutions can issue opinions during law making process on different viewpoints.

In addition, there are non-legislative delegated and implementing acts that are adopted by the European Commission based on expert group consultations. A delegated act is intended to supplement or amend non-essential parts of a legislation. An implementing act is aimed to secure uniform conditions across the Member States on the implementation of a legally binding EU act. (EU 2022b)

The following chapters aim to summarise the relevant EU regulative measures and further specifically concerning items referring to hydrogen and PtX.

3.1.1 Fit for 55

In July 2021, the European Commission published a set of legislation packages which fell under the title of Fit for 55. The policy package aims to reduce the EU´s net greenhouse gas emissions from the comparator levels of 1990 by at least 55 % by 2030. The interconnected proposal package was set to have legislative tools to support the European Green Deal target of Europe being the first climate-neutral continent by 2050 which was presented in December 2019. (EC 2021a)

The legislative package for supporting the green transition consists of different mechanisms such as pricing, targets, rules and support measures. The following figure summarises the main aspects of the Fit for 55 package.

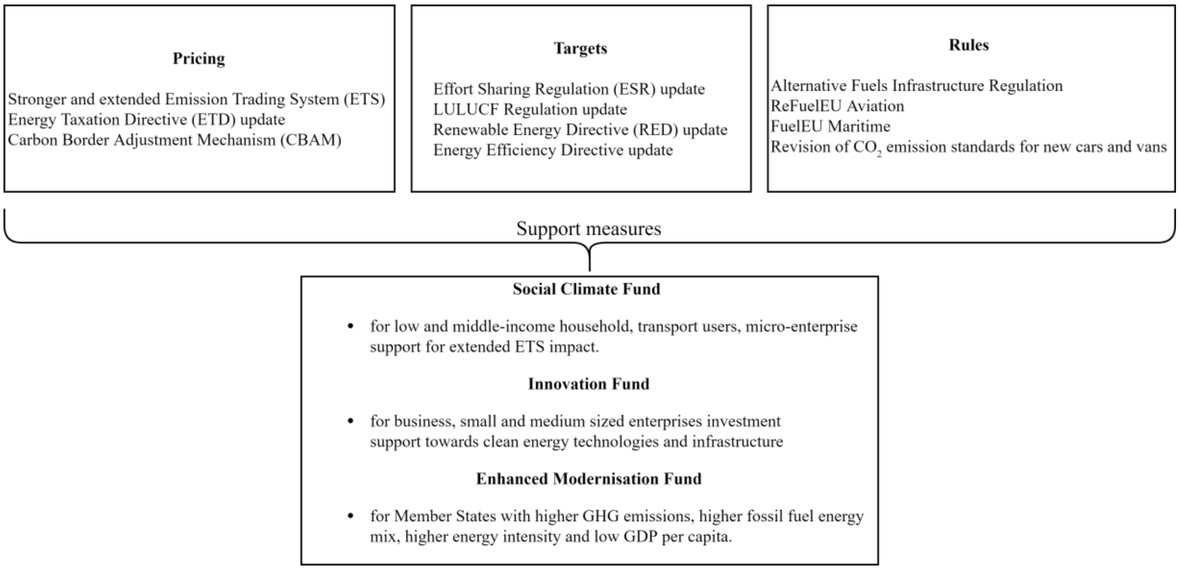


Figure 25. Overview of the EU Fit for 55 package. Gross domestic product (GDP). (EC 2021b, 4-8)

The package is a comprehensive and ambitious set of policy updates and measures to support decarbonisation targets which are needed to reach the emissions reduction targets in the coming decades.

The next chapters will present key parts of the Fit for 55 package that concern hydrogen and PtX products.

3.1.1.1 Renewable Energy Directive amendment

Among the Fit for 55 package there is a delegated act proposal which amends the EU Directive 2018/2001 recast of the Renewable Energy Directive (RED II) that entered into force in December 2018. The overall aim of the amendment is to increase the target of renewable energy sources in the EU´s gross final consumption from the original RED II target of 32 % to be at least 40 % in 2030 (EC 2021c, 2, 30). On a national level, this target has already been met and exceeded in 2020 as the share of renewable energy in final energy consumption was 44.6 % according to the Official Statistics of Finland (2021b). Furthermore, the RED II amendment sets additional targets to different sectors to support the EU wide targets.

The definitions which are applicable for hydrogen and PtX production from RED II article 2 and the amendment are the following:

- ‘Renewable energy’ means energy from renewable non-fossil sources which is namely wind, solar, geothermal energy, ocean energy (tidal, wave), hydropower, biomass, and biogases (EC 2018b, 21)
- The amendment proposal defines ‘renewable fuels of non-biological origin’ (RFNBOs) as liquid or gaseous fuels where the energy content is derived from renewable sources other than biomass (EC 2021c, 28)

In the context of PtX and hydrogen production based on renewable energy, hydrogen and the fuels derived from it falls under the RFNBO category. The CO_2 source for e-fuel production is not explicitly specified in the delegated act nor in RED II, although it is mentioned in the delegated act in a policy scenario model description that CO_2 is sourced from biogenic sources or air capture for transport e-fuels (EC 2021c, 390). However, it can be interpreted that fossil sources of CO_2 are not excluded in e-fuel production. To be truly a carbon neutral e-fuel, it would require biogenic or atmospheric CO_2 sources.

RFNBOs must pass a GHG reduction threshold limit of at least 70 % reduction from the fossil fuel comparator of 94 gCO_2eq/MJ to be considered eligible in the targets. For hydrogen, the EU taxonomy limit for sustainable production is that the GHG emissions on a lifecycle basis should be below 3tCO2e/tH2, which represents a 73.4 % reduction from the fossil comparator. (EC 2022a)

3.1.1.1.1 Notable changes in the amendment proposal

The RED II amendment proposal Article 25 point 1(a) has changed the original RED II target of 14 % renewable energy share in final consumption of energy in transport to a GHG intensity reduction target of 13 % reduction from fossil fuel comparator in transport sector in 2030. In addition, in Article 25 point 1(b) there is a new target that sets the share of RFNBOs to be at least 2.6 % in all transport fuels in 2030. (EC 2021c, 42, 43; Searle 2021, 2, 3)

The amendment proposal also removes several multipliers of the original RED II for fuels, leaving only 1.2 multipliers for advanced biofuels and RFNBOs which are accounted only towards aviation and maritime (EC 2021c, 14). The GHG intensity reduction target represents a significant change to the original RED II by increasing the share of renewable fuels supplied for transport since it takes more fuel to reach GHG savings than having renewable energy content in final consumption and multipliers (Searle 2021, 3).

The drawback of the amendment proposal is that the specification of the methodology for calculating the GHG emissions savings for RFNBOs in Article 29a is mentioned to be supplemented in a delegated act and it has no due date as it had in the original RED II which was by 31.12.2021. Furthermore, the emissions avoidances are not given to CO_2 in RFNBOs if it has received a credit already in the carbon capture from a plant which is operating under other provisions of law which could be e.g. ETS. (EC 2021c, 47, 48; Searle 2021, 4)

Regarding industrial hydrogen use, the amendment proposal includes a new Article 22a which stipulates that 50 % of the hydrogen used in the industry for final energy and non-energy purposes should come from RFNBOs by 2030. The calculation method is based on the energy content on the hydrogen or RFNBO which excludes the hydrogen or RFNBO used as an intermediate to produce transport fuels. Furthermore, the article introduces a labelling procedure for verification of the percentage of RFNBOs or renewable energy used in industrial products. The percentage can be included from raw material acquisition and pre-processing and in manufacturing and distribution stage. The methodology is based on a lifecycle approach according to ISO 14067:2018 or Recommendation 2013/179/EU. (EC 2021c, 37, 38)

Reflecting this requirement to the annual hydrogen use in Finland presented in Figure 5, it would mean that approx. 70000 – 75000 tons of dedicated hydrogen production should be produced with renewable sources when considering the 50 % renewable share requirement.

Article 24 of RED II for district heat and cooling paragraph 4 is replaced to have an increased share of renewable energy and waste heat and cooling share of gross final energy consumption in district heating and cooling by 2030. The share is to be an annual average of 2.1 %-points increase in periods of 2021 – 2025 and 2026 – 2030, starting from 2020 levels (EC 2021c, 40). This could be a potential for electrolysis side stream heat usage in district heating which could be classified as renewable if waste heat is resulting from hydrogen production with renewable electricity. The renewable part of the district heating produced in 2020 in Finland was 44 % of total production as reported by the Official Statistics of Finland (2021c).

3.1.1.1.2 Interpretation of the electricity source for RFNBOs

RED II and its amendment stipulates the electricity source requirements for RFNBO production. In principle, there are two alternatives, either direct connection to a renewable electricity installation or via grid electricity. However, the requirements provide different sets of interpretation alternatives which are summarised in the figure below.

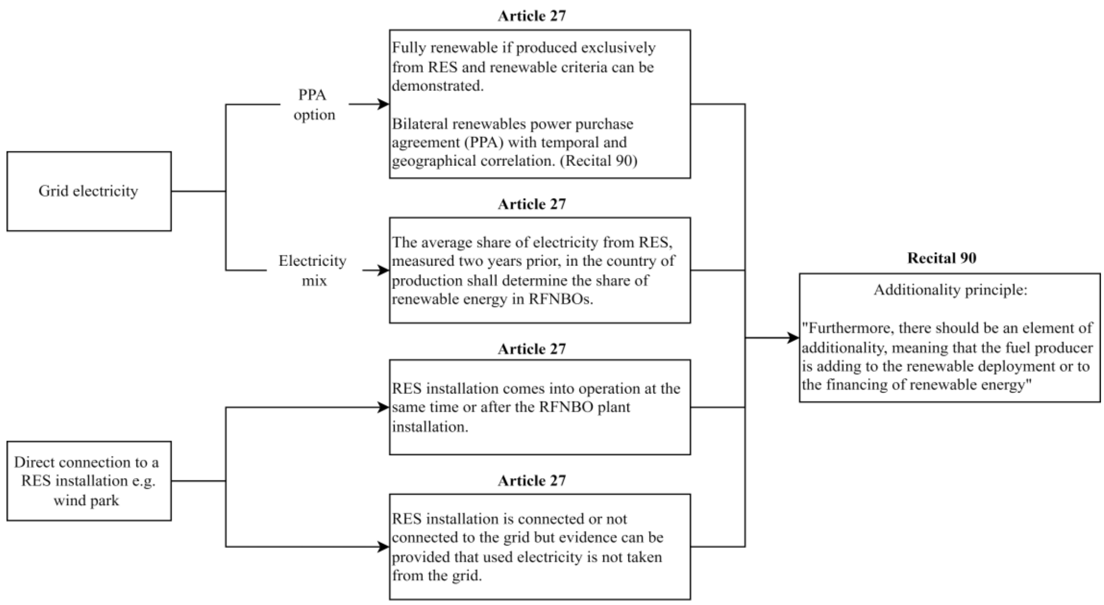


Figure 26. Electricity source alternatives for RFNBO production according to RED II Article 27 and Recital 90. Renewable Energy Source (RES). (EC 2018b, 14, 15, 47; EC 2021c, 44)

Utilising grid electricity with demonstrated renewability criteria with Power Purchase Agreement (PPA) and Guarantees of Origin (GO)[4] seems to be the most straightforward route to produce RFNBOs. Although, Recital 90 requires temporal and geographical correlation which means that RFNBOs cannot be counted as fully renewable if they are produced when the contracted renewable generating unit is not in operation and the RFNBO production and RES installation are located on different sides of the grid congestion (EC 2018b, 14, 15). Strict correlation requirements can be seen as quite restrictive.

The electricity mix alternative can result in non-renewable production as the electricity supply in Finland is not generated with 100 % renewables as of today. In 2020, the renewable share of Finnish electricity production accounted to 34.7 TWh which represents 52 % from total production. While the renewable share of national electricity production is already on a good level, Finland is a net importer of electricity. The net imports in 2020 was 18 % of total electricity consumption. Imported electricity is received from Nordic countries, Estonia and Russia so evaluating the GHG intensity of the electricity mix should also consider imports which could pose a challenge. (OSF 2021c)

Direct connection to a RES installation is also a clear path to produce RFNBOs with a certainty of renewability. However, the timing requirements set in Article 27 can add complexity to matching the timing of RFNBO production and renewable electricity generation. For example, wind energy project execution duration from pre-assessment to completion can take on average 4 – 6 years for a mid-size project with approx. 10 wind turbines while smaller projects with a few turbines can be completed in less than two years (FWPA 2022b). It is thus very much dependant on the scale of the project.

The other alternative is to have a direct connection which is or not connected to the grid so renewability verification for this type of connection could be also provided with a PPA.

Furthermore, all alternatives for RFNBO production should consider the additionality principle in which direct connection supports the addition of renewables and PPA alternatives would support the financing side. Different PPA alternatives are discussed in section 4.1.2.

[4] Guarantees of origin is a verification method to provide evidence that electricity is produced using renewable energy. The GO certificate is an electronic document and it is issued by Fingrid in Finland which complies with the national Act on Guarantees of Origin for Energy (1050/2021) and Government Decree on GOs (1081/2021) as well as Article 19 of the RED II. (Fingrid 2022)

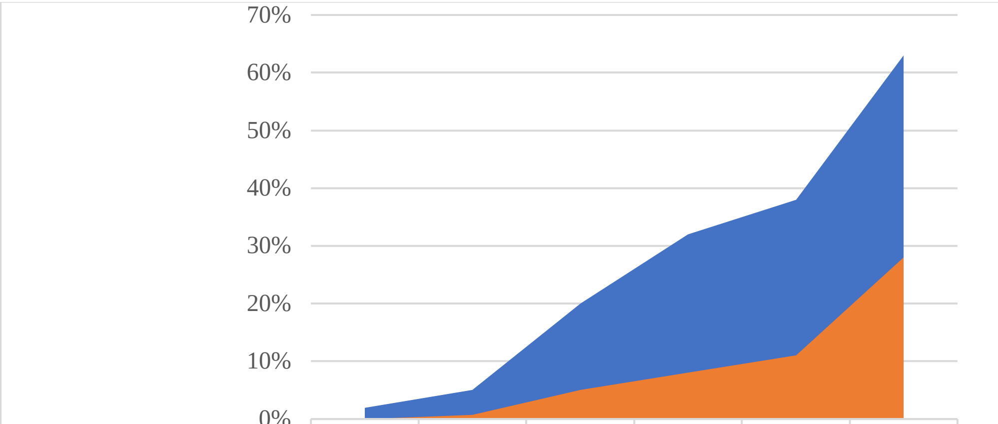
The deadline for Member States on the transposition of the proposed RED II amendment is by 31.12.2024 (Searle 2021, 4). Delayed acts can possibly hinder development and hesitate investments into RFNBO production if the rules are not clear and set appropriately.

3.1.1.2 ReFuel EU Aviation Regulation

The ReFuel EU Aviation is a proposed regulation for the EU aviation sector which aims to decarbonise air transportation. As it is a regulation, it will be directly binding to air transportation in the EU and non-compliance will result in fines as per Article 11 of the regulation. The regulation aims to increase the share of sustainable fuels used in the aviation sector which would become mandatory starting from 2025 while the regulation itself would apply from 1st of January 2023. Article 4 sets the minimum shares of sustainable aviation fuels (SAF) of the total fuel pool that should be available for aircraft operators at Union airports. The aircraft operators are obliged to uplift at least 90 % of their required annual aviation fuel from an Union airport according to Article 5 which prevents fuel tankering i.e. carrying excess fuel from outside of EU to avoid refuelling in an airport with higher fuel costs. Union airports are obligated to provide the necessary infrastructure for the delivery, storage and uplifting of SAF. Fuel producers are obliged to report the volumes, conversion process and lifecycle emissions of the SAF types supplied to an Union airport. (EC 2021d, 2, 18, 22-24)

The term sustainable aviation fuels include drop-in fuels such as advanced biofuels and biofuels which are specified in RED II as well as synthetic aviation fuels which are categorised under RFNBOs. As the synthetic aviation fuels should be drop-in fuels, they would be produced by means of power-to-liquids to be directly applicable for existing fleets. Liquid hydrogen potential is recognised as an alternative propulsion fuel which could start from short-haul flights. (EC 2021d, 15, 21)

Minimum shares of including SAF in aviation fuels is starting from the 1st of January 2025 and the share is gradually increased in 5-year intervals. However, synthetic aviation fuels as a portion of the supplied total SAF share will be necessary to include from the beginning of 2030. The following figure illustrates the minimum volume shares of sustainable aviation fuels and synthetic aviation fuels that should be available at Union airports.



	1.1.2025	1.1.2030	1.1.2035	1.1.2040	1.1.2045	1.1.2050
Sustainable aviation fuels	2%	5%	20%	32%	38%	63%
Synthetic aviation fuels	0%	0.7%	5%	8%	11%	28%

Figure 27. Minimum volume shares of sustainable aviation fuels according to Article 4 and Annex I of the ReFuel EU regulation. (EC 2021d, 21)

The definition of the Union airport according to the proposed regulation states that the size of the airport corresponds to a passenger traffic of higher than 1 million passengers or higher than 100000 tons of freight traffic for the reporting year (EC 2021d, 21). It seems that the regulation would be applicable for larger airports and would not apply to the Vaasa airport since the passenger traffic in pre-pandemic year of 2019 totalled 303911 passengers according to Finavia statistics (Finavia 2022).

3.1.1.3 FuelEU Maritime Regulation

The FuelEU Maritime is similarly a binding regulation that aims to reduce the GHG intensities of marine traffic in the European Union. Maritime transport contributes approx. 75 % of the external trade volumes from the EU and approx. 31 % of the EU internal trade volumes. The significant role of marine transport in the EU economy and its current reliance on fossil fuels drives the need for CO_2 reductions in the sector. Maritime traffic contributes to approx. 11 % of CO_2 emissions from transport in the European Economic Area and 3 – 4 % of total CO_2 emissions in the EU. The aim of the regulation is to increase the uptake of renewable and low carbon fuels in the sector. An obligatory FuelEU certificate will be issued and it is to be carried onboard for verifying compliance. Non-compliance will be met with penalties. (EC 2021e, 12, 20, 33, 34)

Article 2 of the regulation defines the scope and the regulation applies to all ships having a gross tonnage (GT) of above 5000 GT with the exceptions of warships, naval auxiliaries, fishing ships, non-mechanically propelled ships and wooden ships of primitive builds as well as non-commercial purpose government ships (EC 2021e, 21). The regulation will thus be directly applicable to the Aurora Botnia ferry which is operating from Vaasa to Umeå in Sweden and has a gross tonnage of approx. 24300 GT (Wasaline 2022).

Article 4 states the requirements for GHG intensity reductions of the energy used onboard a ship. The yearly average GHG intensity should not exceed the required limits. The limit is set by reducing the reference value of $XgCO_2eq/MJ$ with the percentages and schedules set in the following table, starting from the date that the regulation is entering into force. (EC 2021e, 24, 37)

Table 7. GHG intensity reduction from reference value according to Article 4 of the FuelEU Maritime Regulation. (EC 2021e, 24)

GHG intensity reduction	Schedule
- 2 %	From 1.1.2025
- 6 %	From 1.1.2030
- 13 %	From 1.1.2035
- 26 %	From 1.1.2040
- 59 %	From 1.1.2045
- 75 %	From 1.1.2050

The reference value corresponds to the fleet average GHG intensity of the energy used onboard ships in 2020 and calculating the reference value "will be carried out at a later stage of the legislative procedure" and according to data which is monitored, reported and verified (MRV) under MRV Regulation (EU) 2015/757. (EC 2021e, 24)

The regulation proposal Annex I defines the GHG intensity calculation methods for well-to-tank (WtT) and tank-to-wake (TtW) emissions (Searle 2021, 7). Annex II sets the default values for different fuels. RFNBOs are set to follow the methodology in RED II and they must meet the sustainability criteria otherwise RFNBOs will have the emission factors of similar fossil fuel types (EC 2021e, 21).

RFNBOs (e-fuels) can contribute to the emission reductions and achieve net zero emissions during the lifecycle. Lloyd´s Register (LR) and University Maritime Advisory Services

(UMAS) assessed different fuel types for an example ship and the emission performance for WtT (upstream) and TtW (operational) for different fuels is illustrated in the following figure.

Figure 28. Lifecycle emission performance for different fuels for an exemplary bulk carrier. Low Sulphur Heavy Fuel Oil (LSHFO). Marine Diesel Oil (MDO). (LR, UMAS 2020, 28)

The coloured dots after certain fuels are referring to internal combustion engines or fuel cells as the power source onboard. E-fuels reached the best emission performance and all of them could achieve net zero CO_2 emissions. In the report, renewable electricity and CO_2 from direct air capture was used in the evaluation of hydrocarbon-based e-fuel pathways (LR, UMAS 2020, Appendix B). Although the emission performance was carried out on a specific case study ship, it gives the indication that PtX fuels can provide suitable means of reaching GHG reduction targets in the maritime sector. E-fuels can serve as drop-in fuels and novel fuels such as hydrogen and ammonia will likely be demonstrated in the coming years.

3.1.1.4 Revision of the Directive on the deployment of the alternative fuels infrastructure

The proposed revision of the Directive 2014/94/EU on the deployment of the alternative fuels infrastructure is to change its legal status from a directive into a regulation. The purpose of the change is to have a binding methodology for Member States for increasing the development of alternative fuels infrastructure and thus boost the uptake of low- and zero-emission modes of transportation together with renewable and low carbon fuels. The aim of the regulation is to increase the amount of publicly accessible electric vehicle recharging points and promote the development of alternative fuel refuelling stations along the core and comprehensive Trans-European Transport Networks (TEN-T). (EC 2021f, 2, 3, 27)

The core and comprehensive networks of TEN-T are illustrated in the following figure.

Figure 29. The core and comprehensive networks on the TEN-T with focus on Finland. Rail-Road Terminal (RRT). Modified from (EC 2017, 10).

Alternative fuels means that they are a fuels or power sources which serve as a substitute for fossil oil sources and have the potential for decarbonisation of the transport sector. For zero-emission vehicles they are defined as electricity, hydrogen and ammonia. Synthetic fuels produced with renewable energy are included in the renewable fuels category. The regulation also recognises transitional phase alternative fossil fuels such as LNG and CNG as well as synthetic fuels produced with non-renewable energy. LNG refuelling infrastructure is mainly focused on heavy-duty motor vehicles and maritime ports along the core TEN-T network. (EC 2021f, 28, 38, 39)

3.1.1.4.1 Hydrogen dispensers and clean vehicle directive

Regarding hydrogen, Article 6 stipulates that by 31st of December 2030 the Member States shall ensure that a minimum number of hydrogen refuelling stations are in place. The required hydrogen refuelling stations are to be equipped with at least a 700-bar hydrogen dispenser with minimum capacity of 2 t_{H2}/day. The dispensers are required to be placed at a maximum distance of 150 km from each other along the core and the comprehensive networks of the TEN-T. In addition, the regulation requires to include the availability of liquid hydrogen in the publicly accessible refuelling stations with maximum of 450 km in between LH_2 stations. By the same deadline, at least one hydrogen refuelling station shall be deployed in every urban node[5]. The refuelling stations should be designed to serve light- and heavy-duty vehicles. Freight terminals with refuelling stations should also ensure include liquid hydrogen availability. The responsibility of arranging the requirements concerning dispensing options fall under the operator and/or owner of the hydrogen refuelling station. (EC 2021f, 36, 37)

The regulation proposal can be seen as welcomed and necessary as the uptake of alternative fuels, especially hydrogen, requires proper refuelling infrastructure. In addition to the proposed regulation, although not included in the Fit for 55 package, the revised Clean Vehicles Directive EU 2019/1161 adds to the consumption side for alternative fuels. The revised directive was adopted in June 2019 and transposed into national law by 2nd of August 2021. The directive applies to cars, vans, trucks and buses which are procured through different public contracts such as purchase, leasing and rent contracts, public service contracts for passenger transport or services contracts for e.g. refuse collection, mail and parcel delivery. The directive is applicable for contracts issued after 2nd of August 2021. Clean vehicles

[5] Urban nodes in Finland under the current TEN-T regulation include cities of Helsinki and Turku. However, an updated regulation proposal will extend the urban nodes in Finland to include cities of Jyväskylä, Kuopio, Lahti, Oulu and Tampere. (LVM 2022)

definitions and national procurement targets for Finland are summarised in the following table. (EC 2019)

Table 8. Clean vehicle types and national targets. (EC 2019)

Vehicle type	Definition	National procurement targets [minimum] 2.8.2021–31.12.2025	1.1.2026–31.12.2030
Clean light-duty: Cars, vans	Emission limits: max. 50 g/km CO2 until 31.12.2025 zero-emission after 1.1.2026	38.5 %	38.5 %
Clean heavy-duty: Trucks (over 3.5 tons)	Using alternative fuels: H_2, electricity (BEV, PHEV), liquefied or compressed natural gas or biomethane, LPG, biofuels, synthetic fuels	9 %	15 %
Clean heavy-duty: Buses[1)]	As above	41 %	59 %

Note. Battery Electric Vehicle (BEV). Plug-in Hybrid Electric Vehicle (PHEV). Liquefied Petroleum Gas (LPG). 1) Half of the procurement target for buses to be fulfilled with zero-emission vehicles.

The public procurement is based on national targets with freedom to allocate and not individual city or specific area targets (EC 2019). Vaasa is located along the comprehensive network of TEN-T so if hydrogen refuelling stations will emerge due to the alternative fuels regulation, it could be considered in the public fleet renewal to include zero-emission alternatives such as hydrogen buses.

3.1.1.5 Updated and extended Emission Trading System

The EU Emission Trading System (ETS) is a cap-and-trade system where the Union sets caps on how much GHG emissions can be emitted annually. Companies must hold European Emission Allowances (EUA) for each ton of emitted CO_2 within a calendar year. These emission permits are received and they can be bought and traded. Fines are issued if the emissions exceed the permitted allowances. Excess allowances achieved by implementing energy efficiency activities can be sold which incentivise the adoption of measures that increase efficiency and reduce emissions. (Appunn 2021)

The current ETS applies to power plants and energy intensive industries such as the production of iron, paper, cement, aluminium and others as well as aviation in the EU. The energy related activities that are included in the ETS refers to combustion of fuels for installations that have a thermal input of over 20 MW which excludes the incineration of MSW or hazardous waste. (EC 2021g, 53, 54, 55)

Under the Fit for 55 package the EU ETS directive has received an update proposal which aims to increase the reach of the ETS to additional sectors that it currently governs. The updated proposal would include maritime transport as a new entry to the current ETS and set a separate ETS system for buildings and road transport sectors.

The addition of maritime sector in the ETS would include ships over 5000 GT regardless of their flag which are travelling from or to EU ports. The ETS will be applicable for 50 % of the emissions for ships departing from an EU port and arriving outside of the EU jurisdiction and vice versa. The ETS will be fully applicable for all voyages within the EU. Failing to meet the requirements results in fines and ships can be denied of port entry. The ETS for the maritime sector will be gradually phased in and shipping companies must surrender their allowances to compensate emissions as per the schedule described below: (EC 2021h, 7, 18, 43, 44)

- 20 % of verified emissions for the reporting year of 2023
- 45 % of verified emissions for the reporting year of 2024
- 70 % of verified emissions for the reporting year of 2025
- 100 % of verified emissions for the reporting year of 2026 and each year after

The new separate ETS for buildings and road transport will run alongside the updated ETS and will target the fuels used for combustion in road transport and building sectors. The aim is to reduce the emissions by 43 % in 2030 compared to 2005 levels and the cap on emissions is set to start from 2026. The regulation targets the fuel suppliers and a quarter of the revenues achieved by the new ETS will be directed to the Social Climate Fund. The extended reach of the new ETS will have an impact on the costs of living so the Fund can be used to support households and energy efficiency improvements. (Appunn 2021)

3.1.1.5.1 ETS cap and price development

The overall annual ETS emission cap will be reduced over time with a linear reduction factor of 4.2 % starting from the date of the transposition of the new ETS directive which is by 31st of December 2023. The increased cap reduction rate aims to reduce overall emissions by 61 % by 2030 compared to 2005 levels as opposed to previous 43 % target. In addition, the free allowances will be reduced by 10 % per year for EU emitters and fully phased out for aviation by 2027. A separate legislation called the carbon border adjustment mechanism (CBAM) is proposed to prevent carbon leakage for different sectors due to ETS. CBAM will introduce a CO_2 price for products or electricity which are imported outside of EU and under the regulation which initially covers cement, iron, steel, aluminium, fertilisers and electricity sectors. (Appunn 2021; EC 2021h, 19, 66; EC 2021i)

As the ETS is a market-based system, the price is governed by supply and demand. Reducing caps and free allowances will increase the price and the CO_2 price per emitted ton has been steadily rising lately. The following figure illustrates the price development of the EUA during the last year.

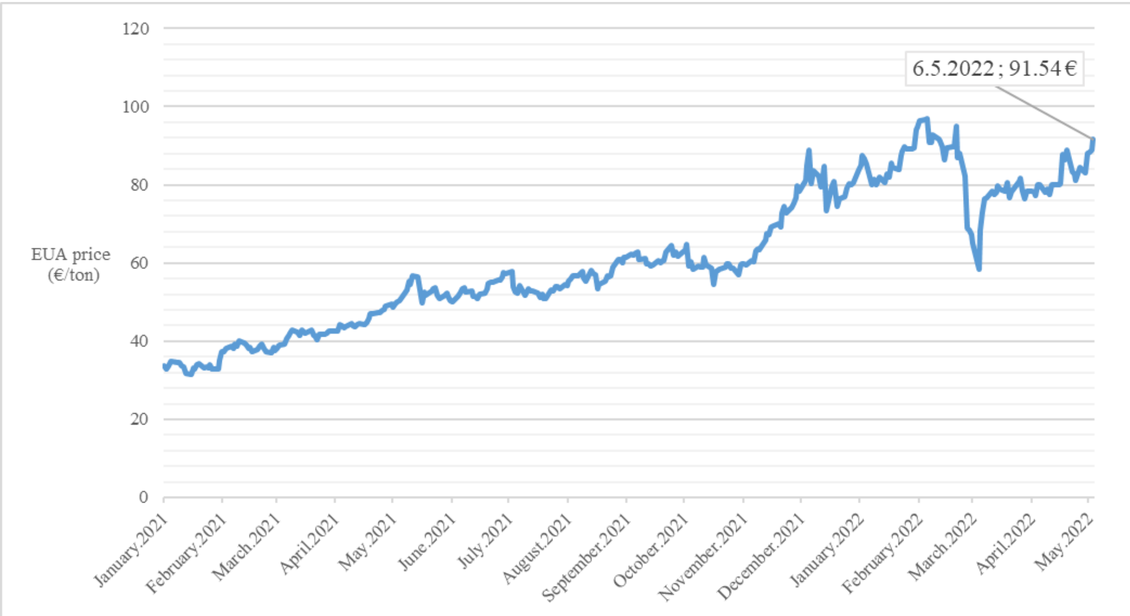


Figure 30. The EUA price development. Data from (Ember 2022).

The price of EUA reached its all-time high in February of 2022 with 96.93 € / ton and the upward trajectory is expected to continue in the following years.

The emissions can be calculated as per the Annex II of the ETS directive (2021h) which is described in equation 10.

$$\text{Emissions} = \text{Fuel released for consumption} \times \text{emission factor} \qquad (10)$$

Fuel released for consumption shall be the quantity of fuel used and the emission factor is taken from the 2006 IPCC Inventory Guidelines or fuel-specific emission factors which are identified by independent accredited laboratories. Furthermore, the Annex I of the ETS directive (2021h) includes the production of hydrogen and synthesis gas with production capacities exceeding 25 ton / day under the ETS so increased carbon prices will have an increasing cost effect on non-renewable hydrogen production.

The inclusion of CCU and CCS activities is promoted by allocating ETS revenues to The Innovation Fund where it can be distributed to innovative projects. CCU, CCS and renewable energy and storage can access the funds if the projects are deemed to contribute to the mitigation of climate change. The projects that apply CCU technologies can deliver net reduction in emissions with permanent CO_2 storage or avoidance of emissions. In addition, CCU projects involving the substitution of carbon intensive alternatives in the ETS sectors are also recognised. (EC 2021h, 49, 50)

3.1.1.6 Updated Energy Taxation Directive

The Energy Taxation Directive (ETD) is being revised under the Fit for 55 proposal package. The update proposal for the ETD aims to reform the minimum taxation levels of different energy products to align with the environmental targets and steer towards sustainable alternatives. The ETD specifies the minimum excise duty rates in €/GJ to be used in Member States for energy product taxation. The energy products that are under ETD are electricity and fuels used for motors and heating. The ETD recast will include hydrogen and alternative fuels and the structure will favour sustainable alternatives to give a clear price signal and facilitate the transition from fossil fuels to cleaner fuels. (EC 2021j)

A new and significant change proposal to the ETD is that the previously tax-exempted sectors of aviation and maritime transport would now be included. The minimum taxation levels would apply to intra-EU flights and maritime transport. Maritime sector would be subjected to a lower taxation level that is similar to the agricultural sector rate to avoid ships bunkering outside the EU. Aviation minimum tax rates will be gradually introduced during the transitional period. In both sectors, sustainable and alternative fuels are promoted as they will have a minimum tax rate of zero for the 10-year transitional period. The following table summarises the proposed minimum tax rates for energy products. (EC 2021j)

Table 9. Minimum taxation rates for different energy products according to ETD recast.

Energy products	**Rate at start of transitional period (01.01.2023) in €/GJ**		**Final rate after completion of transitional period (01.01.2033) in €/GJ**	
	Motor fuel use	**Heating fuel and motor fuel use[1]**	**Motor fuel use**	**Heating fuel and motor fuel use**
Conventional fuels Petrol, Diesel, Kerosene, Heavy fuel oil	10.75	0.90	10.75	0.90
Fuels supporting decarbonisation Liquefied Petroleum Gas, Natural gas	7.17	0.60	10.75	0.90
Low-carbon fuels Hydrogen from SMR + CCS and related fuels	0.15	0.15 / 0[1]	5.38	0.45
RFNBOs and advanced biofuels Hydrogen from RES, e-fuels, biogas, biofuels	0.15	0.15 / 0[1]	0.15	0.15
	Rate at start of transitional period (01.01.2023) in €/GJ		**Final rate after completion of transitional period (01.01.2033) in €/GJ**	
Electricity	0.15 / 0[1]		0.15	

Note. 1) Lower fuel and zero rates for maritime sector for the transitional period. Aviation fossil fuel minimum rate starts from zero and ends up at min. 10.75 €/GJ for e.g. Kerosene after transitional period. Steam Methane Reforming (SMR). Data from (EC 2021k, 41, 42, Annex I).

The ETD revision proposal recognises also fossil gaseous fuels i.e. natural gas as supporting fuels for decarbonising efforts, so they have a slightly lower rate than traditional liquid fossil fuels before ending up at the same rate after the transitional period. Similarly, blue hydrogen enjoys a lower rate for the transitional period. Applying a zero rate for the transitional period and a very low rate after the transitional period for e-fuels and renewable hydrogen should provide incentive and direct the use and uptake towards renewable alternatives.

3.1.1.6.1 Impact of ETD and ETS

Including maritime in the ETD and ETS will cause additional fuel costs towards operation depending on the fuels used. To illustrate their impact on fuel costs, the below equation is used for evaluation.

$$\text{Total fuel costs } [€/\text{ton}] = \text{Bunker price } [€/\text{ton}] + \overbrace{\text{Emissions} \times \text{EUA price}}^{\text{Emission costs } [€/\text{ton}]} + \overbrace{\text{LHV} \times \text{fuel use} \times \text{min. tax}}^{\text{Tax rate } [€/\text{ton}]} \tag{11}$$

The bunker prices as €/ton are taken as 6-month average values from Rotterdam bunker prices according to Ship & Bunker (2022) and USD to EUR conversion rate of 0.9476 (ECB 2022). Emissions are calculated according to eqn. (10) by using fuel emission factor ($gCO_2/gFuel$) default values which are taken from Fuel EU Maritime Annex I (2021e, 21) and assuming 1 ton of fuel used. The EUA price is the highlighted value (91.54 €/tCO2) from Figure 30. Similarly, the default LHVs for different fuels are taken from Fuel EU Maritime Annex I and the minimum tax rate for fuels as per Table 9. The following figure summarises the impact of ETD and ETS for different fuels.

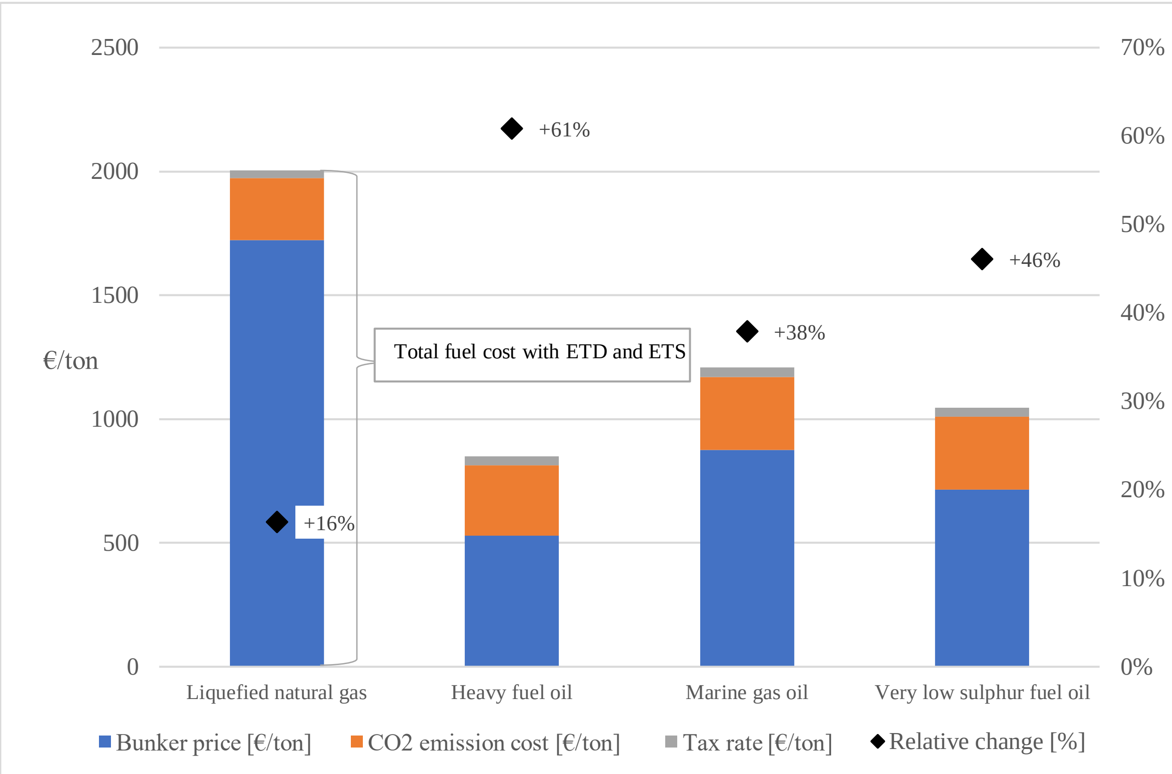


Figure 31. Comparison of ETD and ETS impact on different marine fuel costs.

It can be noted that the impact of ETD and ETS on marine fuel costs is considerable, especially for heavy fuel oil. Naturally, the relative change is amplified on low-cost fuels, however the price signal is notable. E-fuels can benefit from 0 € tax rate for marine fuels until 2033 so the savings can be considerable provided that their cost is on par with their fossil fuel equivalents. ETS cannot be avoided if the e-fuels serve as drop in fuels i.e. SNG will have a similar emission factor than natural gas. Ammonia and hydrogen will have an emission factor of zero according to the Fuel EU Maritime directive so the ETS will not impact these fuels.

3.1.2 CertifHy

Apart from the Fit for 55 package a hydrogen certification scheme is under development by CertifHy. CertifHy is a consortium which has been created by the request of the European Commission and it is financed by the Clean Hydrogen Partnership. The aim is to create an EU-wide system of GOs for hydrogen which can be used to e.g. provide proof of compliance regarding RED requirements. CertifHy scheme is targeting in becoming a Voluntary Scheme to certify RFNBO compliance to the RED II recast criteria. (CertifHy 2022a)

The GO is issued to a production device and will be based on 1 MWh (LHV) unit value. The GO will include information such as: (CertifHy 2019, 13, 14)

- Production device identification
- Timestamp of production batch
- Energy and technology used for production
- Financing support information if applicable
- Share of renewable energy in % for each input to produce hydrogen
- GHG balance as GHG emission intensity in gCO_2/MJ
- GO identification, issue and expiration date, name of certification body
- CertifHy label as Green hydrogen or Low-Carbon hydrogen

Currently, the CertifHy GHG threshold for green and low-carbon hydrogen is min. 60 % below of the reference value of 91 gCO_2eq/MJ from hydrogen produced by means of SMR. This equals a limit of 36.4 gCO_2eq/MJ for green and low-carbon labels. Green labels are issued for hydrogen produced from renewable sources. Low-carbon labels are issued for hydrogen produced with non-renewable sources such as nuclear or fossil energy with CCS if they meet the required GHG threshold. (CertifHy 2022b)

There are currently some discrepancies on the CertifHy GHG calculation methodology as two different methods are used for GHG accounting. The Disclosure method is based on ISO 14067:2018 which assesses the carbon footprint of hydrogen with a “Cradle-to-Gate” or “Well-to-Gate” method. The Compliance method for demonstrating regulatory compliance which would be based on the previously discussed GHG saving criteria of RED II recast and would follow a “Cradle-to-Grave” accounting. The different methods are illustrated in the following figure. (Barth 2022, 4)

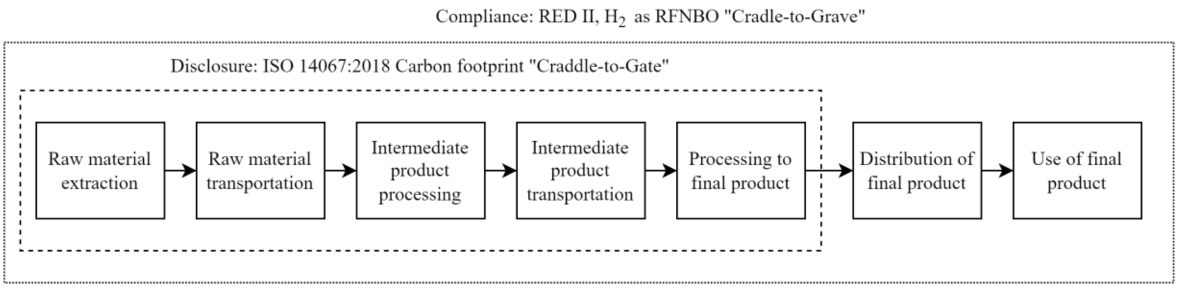


Figure 32. Different GHG calculation methodologies in CertifHy scheme. Modified from (Barth 2022, 4).

As it should be straightforward to account the GHG emissions from water electrolysis with renewable electricity, it may include GHG accounting from raw material emissions as in the case of electrolysis via SOEC. This means that the renewability of the steam input will be assessed as to whether it is produced strictly from renewable sources or whether it has a mix of renewable and fossil sources. Steam source and the electricity source will determine the final renewable energy content of hydrogen produced with SOEC. (Barth 2022, 8)

The GO scheme for demonstrating hydrogen origin could provide value for the producers and for off-takers as it will provide a proven record of the methods of hydrogen production. However, the certification scheme should be in harmony with different methodologies so that it will be clear for all parties.

3.1.3 Gas and hydrogen decarbonisation package

In addition to the Fit for 55 package, the European Commission published the gas and hydrogen decarbonisation package on the 15th of December 2021. The aim is to facilitate the integration of renewable and low-carbon hydrogen and gases in existing and new infrastructure and reduce the reliance on fossil natural gas. The proposal package is introducing a revision of the Regulation on natural gas transmission networks and a revision on the Directive on common rules for the internal market on natural gas. The proposal package supports the EU Hydrogen Strategy target of having 40 GW of electrolyser capacity for renewable hydrogen production and 10-million-ton hydrogen production target by 2030.

Renewable gases mean the RFNBOs as defined in RED II revision and low-carbon is produced from non-renewable sources but meeting the 70% GHG savings threshold. Furthermore, the regulation and directive are intended for gas transmission and distribution system operators. (EC 2021l)

3.2 National regulations

National regulations regarding hydrogen and power-to-x will closely follow the regulations and directives set forth on the EU level. This section will aim to describe the relevant actions that have been presented on a national level.

3.2.1 Distribution obligations

The purpose of the Distribution Obligation Act 446/2007 is to promote the use renewable fuels in the transport sector. The Act was revised in 2021 and entered into force on the 29th of June 2021. Fuel distributors must include a certain share of renewable fuels in the fuels released for consumption. The Act applies to fuel distributors which release gaseous transport fuels for consumption of over 9 GWh during a calendar year. Similarly, the limit for liquid fuels released for consumption is over 1 million litres. In Finland, the Energy Authority is the governing body which manages the approvals for distributors and monitors the fulfilment of the Act. (Finlex 2021, 3 §, 4 §, 15 §)

In the context of power-to-x, the amended Act now includes RFNBOs as part of the distribution obligations for renewable fuels. The following table illustrates the distribution obligation renewable share increases in the coming years.

Table 10. Renewable fuel distribution obligations. (Finlex 2021, 5 §)

Year	2022	2023	2024	2025	2026	2027	2028	2029	2030
Distribution obligation [%]	19.5	21	22.5	24	25.5	27	28.5	30	30
Additional obligation* [%]	2	2	4	4	6	6	8	9	10

Note. *) Additional obligation sets the minimum share of the distribution obligation that should be fulfilled with biofuels derived from sources described in attachment A of the Act or with RFNBOs.

The renewable share of fuel in the distribution obligation is calculated based on the energy content of the renewable and fossil fuels released for consumption by the fuel distributor during the specific calendar year. The calculation is shown in the eqn. (12) below. (Energy Authority 2022, 22)

$$\text{Distribution obligation [\%]} = \frac{E_{\text{renewable}}}{E_{\text{renewable}} + E_{\text{fossil}}} \tag{12}$$

The distribution obligations will apply to RFNBOs only after the 1st of January 2023 (Finlex 2021, 15 §). Nevertheless, by 2030, roughly a third of the fuels released for consumption should be of renewable origin.

3.2.2 Medium-term Climate Change Policy Plan

The Ministry of the Environment has set forth an update of the Medium-term Climate Change Policy Plan as a part of the means in achieving the carbon neutrality target of 2035. The policy plan is drafted once in an electoral year and it includes an action plan for the sectors that are not covered under the ETS. The regulation which covers waste management and waste incineration in Finland is the Effort Sharing Regulation (ESR). As part of the Fit for 55 package, the ESR has been proposed a revision which sets updated targets for Member States. The proposed targets in the revised ESR would increase the Finnish emission reduction obligations regarding ESR sectors to 50 % from the current 39 % target. Emissions from the ESR sectors should be reduced with a linear reduction rate to achieve the reduction target in 2030 compared to 2005 levels. The ESR sector emissions would amount to 17.2 MtCO2eq in 2030 with the revised target. (YM 2021, 18, 29, 49)

Waste incineration share of the total ESR sector emissions is approx. 2 % and the policy plan has set a target that the emissions resulting from waste incineration should be reduced 0.1 Mt by 2030. The policy measure set forth for reaching this target is to establish a waste incineration green deal which is a voluntary agreement for the reduction of GHG in the complete waste value chain. In addition, the policy measures include the piloting of CCS/CCUS technologies in waste incineration plants. In the long term, the target for waste incineration is to reduce emission by one third and the need for CCS technologies is recognised to reach the long-term targets. (YM 2021, 48, 124, 125)

The distribution obligation is suggested to be increased to 34 % or possibly until 40 % for the year of 2030 (YM 2021, 88). This would contribute significantly on the adoption of biofuels which could also increase RFNBO potential.

The final report of the policy plan is under preparation at the time of writing this thesis and it is expected to be completed by end of June 2022.

3.2.3 HyLAW

The HyLAW (Hydrogen Law) project is a multinational project with the aim of providing clarity on the existing regulations that can be applied to hydrogen and fuel cell technologies. It comprises of 18 different countries and the purpose is to provide market developers and policy makers information about different legal barriers on the deployment of hydrogen applications. The HyLAW partner countries are classified as front runners, fast-followers or emerging countries in the context of the technology development of hydrogen applications. Finland is classified as a fast-follower and on a national level, there is a long history of large-scale industrial hydrogen production. (Kotisaari et al. 2018, 4, 6)

In the context of PtX, the amount of hydrogen produced specifies the need of different authority involvement. If the quantities are at a small scale of 100 – 2000 kg, local rescue authorities supervise and permit the hydrogen production or hydrogen refuelling station. For below 100 kg quantity, there are no requirements for permit or notifications to the rescue authorities. Hydrogen amounts exceeding 2000 kg fall under the operational permit of the Finnish Safety and Chemicals Agency (Tukes). Hydrogen production can be categorised as centralised or localised. Centralised production implies large-scale production and hydrogen applications in a wider geographical area which requires hydrogen transportation. Localised production is implying to small-scale production where hydrogen is utilised on site and there´s no need for transportation. (HyLAW 2018; Kotisaari et al. 2018, 6)

The HyLAW project has developed an online database where different sets of regulations are compiled based on their application. The following Figure 33 gives an overview of different legislations and processes that are listed in the database and concern PtX together with methanation. The overview is based on large-scale centralised hydrogen production. Localised production can have a “simplified” process which still requires following the legislation concerning environmental protection, land use and building as well as monitoring of the handling and storage of dangerous chemicals. The purpose is not to open the legislations further but to give a brief insight to national level regulations concerning the practical application of PtX at current state.

	Hydrogen production	Hydrogen storage	Hydrogen transport & distribution (Road)	Gas grid (SNG)	Electricity grid
LAP	- Land use plan - Permitting process & requirements	- Land use plan - Permitting process & requirements	- Permitting process & requirements - Quantity and pressure limitation - Road planning	- Permissions and restrictions - SNG injection and H_2 content	- Connecting electrolyser to the electricity grid (as a consumer) - Legal status of power-to-gas plants and energy storage facilities
National legislation	- Land Use and Building Act (Land use, permitting) - Act on the Safety Handling of Hazardous Chemicals and Explosives (Land use, permitting) - Government Decree on Safety Requirements for Industrial Handling and Storage of Dangerous Chemicals (Land use) - Finnish Safety and Chemicals Agency (Tukes) guidelines for siting process plants (Land use) - Government Decree on the Monitoring of the Handling and Storage of Dangerous Chemicals (Permitting) - Environment Protection Act (Permitting) - Environment Protection Decree (Permitting) - Decree on protection of workers potentially at risk from explosive atmospheres (Permitting)		- Master list of ADR regulation information by the Finnish Transport and Communications Agency (Traficom). - Road transport agreement law. - Transportation of dangerous goods (ADR).	- Decree on safety of handling natural gas - Act on the Safety Handling of Hazardous Chemicals and Explosives	- General connection terms of the Transmission network operator (Fingrid). Connection design, technical requirements etc. - Legislation same as for hydrogen production / storage
Notes	- Local municipality issues building permits. - Permitting process duration approx. 1 year. - Regional State Administrative Agencies issues environmental permits. - Hydrogen production / storage of over 2000 kg requires operational permit from Tukes. - Symbol "T/Kem" for sites that pose a major accident risk.		- No specific pressure limitations if gas cylinder is certified. - Transportation of over 333 litres of hydrogen is under ADR.	- Transmission system operator monitors the gas quality on the grid. - SNG must meet required quality. - H2 limit is max. 1 % in natural gas.	- Distribution network operators in local grids follow Fingrid terms. - The legal status of a power-to-gas plant is categorised as an industrial plant.

Figure 33. Overview of legal and administrative processes (LAP) and national regulations based on different stages of power-to-x process. Compiled from the HyLAW online database (2018).

Furthermore, there are several specific EU level legislations that apply to the different stages as well such as the SEVESO III and ATEX directives. SEVESO directive, which relates to the control of major accident hazards involving dangerous substances, applies to quantities of hydrogen of over 5 tonnes. ATEX directive covers the equipment and protective systems intended for use in potentially explosive atmospheres and specifies zone classifications.

The need of developing a national hydrogen regulation by the Ministry of Economic Affairs and Employment with safe use of hydrogen guidelines from Tukes is recognised in the national policy recommendations (Kotisaari et al. 2018, 6). Furthermore, the regulations should include the production of different RFNBOs. Clear and specific regulations are required if hydrogen and PtX applications will become mainstream in the national energy scheme.

4 Economic aspects

This section will cover the relevant economic aspects that are concerning the power-to-x processes. The purpose is to provide an overall picture of the key capital expenditures (CAPEX) and operational expenditures (OPEX) and possible revenue from side streams.

4.1 Electricity costs

As water electrolysis is based primarily on converting electrical energy into hydrogen, the electricity costs represent a major part of the OPEX of an electrolyser plant.

4.1.1 Nord Pool and electricity tax

Nord Pool is the marketplace for wholesale electricity in 16 European countries and it's the nominated electricity market operator in Finland. The wholesale system price is determined by supply and demand. Weather and power plant availability affects the price as well. The Nordic countries are divided into bidding areas where area specific hourly pricing occurs to reflect regional market conditions such as transmission constraints, thus the price can deviate from the system price. (Nord Pool 2020)

The hourly area prices for the year 2021 in Finland is illustrated in the following figure.

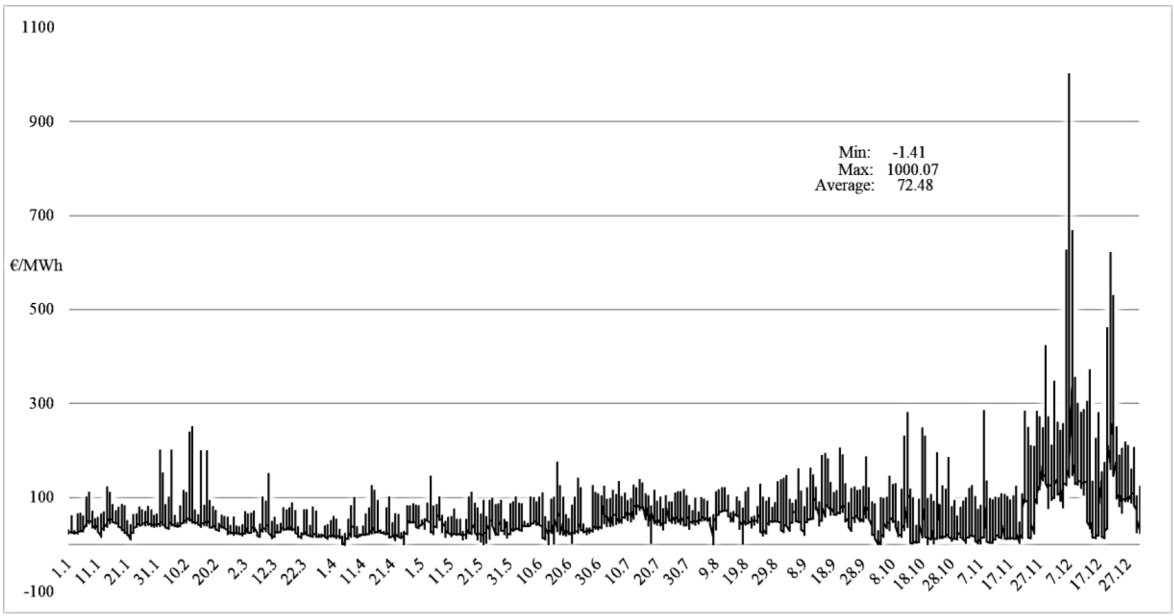


Figure 34. Hourly Elspot prices for the year 2021 in Finland. Data from (Nord Pool 2021).

As it can be seen, drastic variations in pricing can occur when demand is high during wintertime in Finland since the demand for heating is increasing and when combined with industry needs, the variance is amplified. Due to the variable prices, dynamic operation of the electrolyser would be required to take advantage of lower spot prices.

The spot prices do not include transmission fees, value added tax (24 %) nor the electricity tax. The electricity tax for category II is 0.063 c/kWh which includes the energy content tax and the strategic stockpile fee. The category II is intended for industrial applications and data centres. However, power plant or CHP plant own use equipment and storing electricity in an electricity storage are exempt from excise taxes. (Vero 2021) The exemption could thus apply to electricity used in an electrolyser since they are, in principle, storing electricity as hydrogen. This could at least apply if hydrogen is converted back to electricity, however, the definition is open to interpretations.

4.1.2 Power purchase agreements

Another form of electricity purchasing is PPAs which are used to purchase electricity produced from renewable sources. PPAs are long-term electricity purchase contracts where typically a large electricity consumer agrees to purchase a certain amount of electricity with a certain price over a fixed term. The PPA contractual term lengths are typically 10 – 20 years and this type of agreement provides predictability and stability for the electricity price for the buyer and the producer. (FWPA 2019, 5)

The contractual categories of PPAs are divided into two categories which depends on the delivery method of the purchased electricity. The two categories are summarised below: (FWPA 2019, 16, 17)

- *Physical PPA***.** Electricity is transferred from producers' electricity balance to buyers' electricity balance. Physical delivery of electricity either with direct connection (direct PPA) or via 3rd party (sleeved PPA) who manages the transmission network and acts as the balance responsible party. Typically fixed price agreements.
- *Synthetic (or virtual) PPA.* Involves no physical delivery of electricity. Producer sells the produced electricity to the market and buyer purchases the consumed electricity from the market. A fixed strike price is agreed, and the annual price difference is

settled afterwards between the parties. This type of agreement is referred as a Contract for Difference (CfD).

The following figure illustrates the differences between the two agreement types.

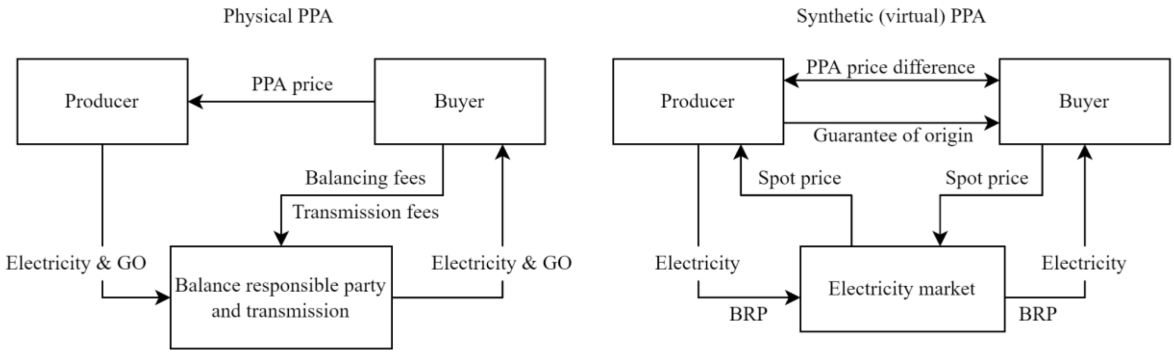


Figure 35. Physical and synthetic PPA differences. GO = Guarantee of Origin. BRP = Balance Responsible Party. Adapted from (FWPA 2019, 16, 17).

The GOs are transferred in both options to the buyer which is required for demonstrating renewability and the compliance of RED criteria for producing RFNBOs with renewable electricity.

The economic outcome of both alternatives will end up in a similar €/MWh price. The following figure illustrates the annual price outcomes for a physical PPA and a virtual PPA with an example price and term.

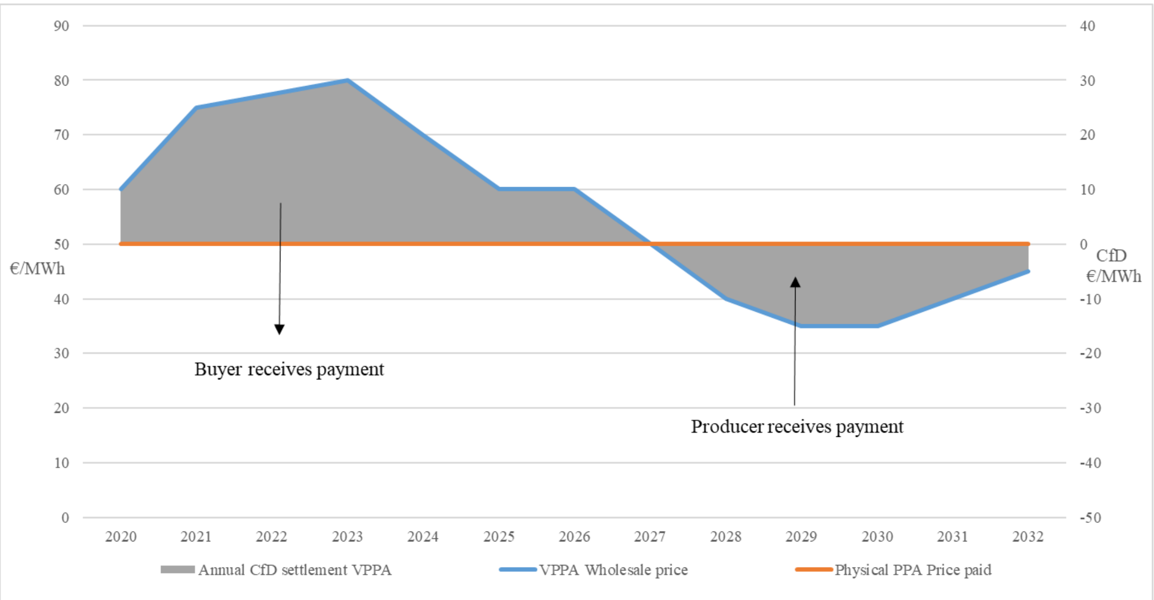


Figure 36. Physical and virtual PPA (VPPA) economic outcomes. Example PPA rate of 50 €/MWh. Data from (WBCSD 2021, 9).

LevelTen Energy provides quarterly reports of European PPA price indices for different countries. The 25th percentile (P25) price indices for wind power PPAs are shown in the following figure.

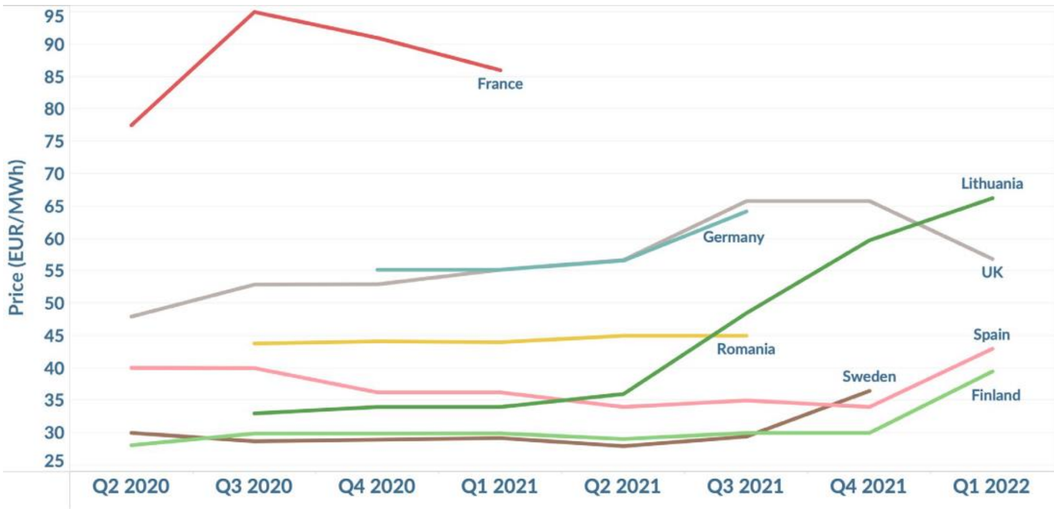


Figure 37. Quarterly wind P25 price indices per country. (LevelTen Energy 2022, 9)

The competitive wind project developers PPA prices in Finland have been steadily hovering around 30 €/MWh for the vast part of 2021, however in Q1 2022 it has increased to approx. 39.5 €/MWh. The increase was due to elevated wholesale market levels (LevelTen Energy 2022, 9). Although, the prices are representing the lowest quartile of offers, it indicates that PPAs can provide competitive electricity pricing compared to average spot pricing as shown in Figure 34. Naturally, PPA prices do not include taxes or transmission fees that vary across regions. To illustrate the PPA price versus spot pricing, the below figure shows the frequency of below 40 €/MWh prices at different hours of the day that occurred during 2021.

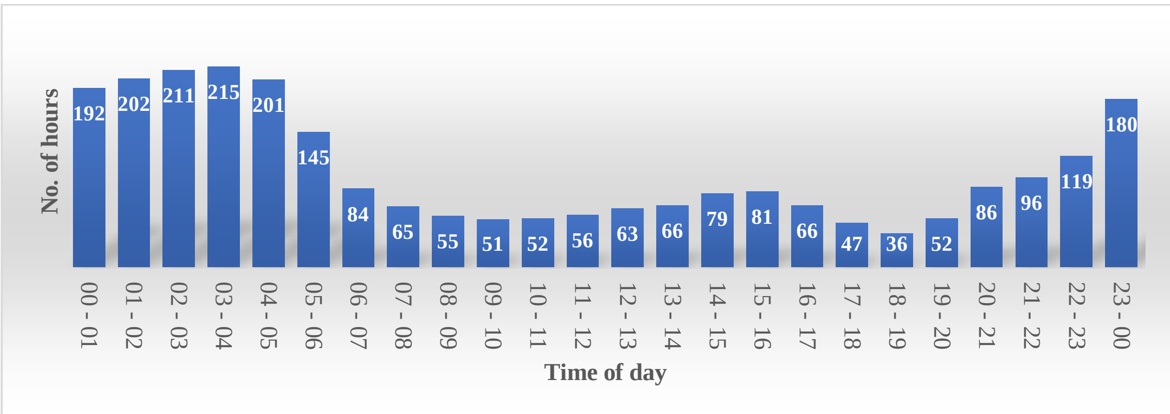


Figure 38. Hourly spot price frequency for below 40 €/MWh in Finland during 2021. Total 2500 hours. Data from (Nord Pool 2021).

As it can be seen, similar price levels occur only during off-peak times and the total hours are quite low which would indicate low running hour and dynamic operation requirements for an electrolyser to utilise low spot prices.

PPAs can have different pricing models such as pay-as-produced and baseload PPAs. In pay-as-produced PPA, the buyer purchases the projects (e.g. wind park) whole electricity production and pays according to actual production. A baseload PPA is based on a fixed production amount where the buyer expects to receive an agreed amount of electricity and the producer is obligated to deliver with their own production, if not met, the producer purchases the remainder from the market. (FWPA 2019, 20)

A baseload PPA would thus be a suitable alternative if hydrogen is produced at a continuous rate. The risk is, in this case, on the producer side which can affect the PPA pricing.

4.2 Electrolyser costs

As electrolyser technologies have not yet reached the state of mass production, the capital costs are developing and can have a wide range of values. An example of literature values for investment cost ranges for different electrolyser technologies are described in the table below.

Table 11. Electrolyser CAPEX ranges.

Technology	Literature CAPEX ranges in €/kW$_e$	
AEL	800 – 1500[1]	600 – 2600[2]
PEM	1400 – 2100[1]	1900 – 3700[2]
SOEC	> 2000[1]	1350 – 3250[3]

Note. Values collected from: ([2]: Brynolf et al. 2018, 8; [1]: Buttler, Spliethoff 2018, 12; [3]: Lux, Pfluger 2020, 8)

The development stage of each technology is reflected in the costs. As the most mature technology, AEL is on the lower end of the cost ranges. Commercialisation stage PEM electrolyser costs are higher due to noble materials used in the stacks. SOEC is the costliest of the three with a high uncertainty due its developmental stage.

The main cost driver for AEL and PEM is the stack. While in the case of SOEC, the stack has a lower share while BoP is higher which can be attributed to the high temperature operating conditions (Anghilante et al. 2018, 13). The indicative cost breakdown for different electrolyser technologies is shown in the following figure.

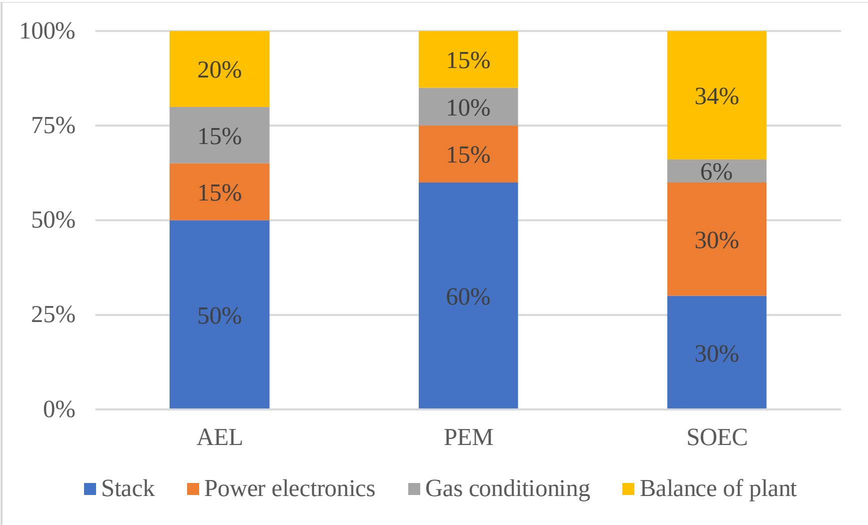


Figure 39. Main module cost breakdown for different electrolyser technologies based on average system costs. Adapted from (Böhm et al. 2019, 10).

Cost reductions can be usually achieved with mass production. Learning curves in production describe the decreasing costs due to the experience gained through doubling cumulative production of the technology. It is expected that the cost reduction potential is the highest with SOEC as it is a novel technology, followed by PEM and AEL. (Böhm et al. 2019, 3, 14)

The learning effect is typically also known as economies of scale (EoS) where scaling the production process from unit to series production will reduce unit costs. EoS can also be used in estimating cost reduction via scaling effect of e.g. increased nominal power. The following equation is commonly used to estimate the scaling effect. (Zauner et al. 2019, 12)

$$C_b = C_a \times \left(\frac{S_b}{S_a}\right)^f \tag{13}$$

Where C_b is the equipment cost at scale S_b, C_a is the reference equipment cost at scale S_a and f is the scaling factor. The scale factor in eqn. (13) can be applied for a specific technology if it is known, otherwise a default value of $f = 0.6$ can used for approximation. The equation is also known as the "six-tenth-factor rule" based on the default scaling value. (Zauner et al. 2019, 12) The following graph illustrates the scaling effect based on literature cost values at different power ratings for AEL and PEM electrolysers.

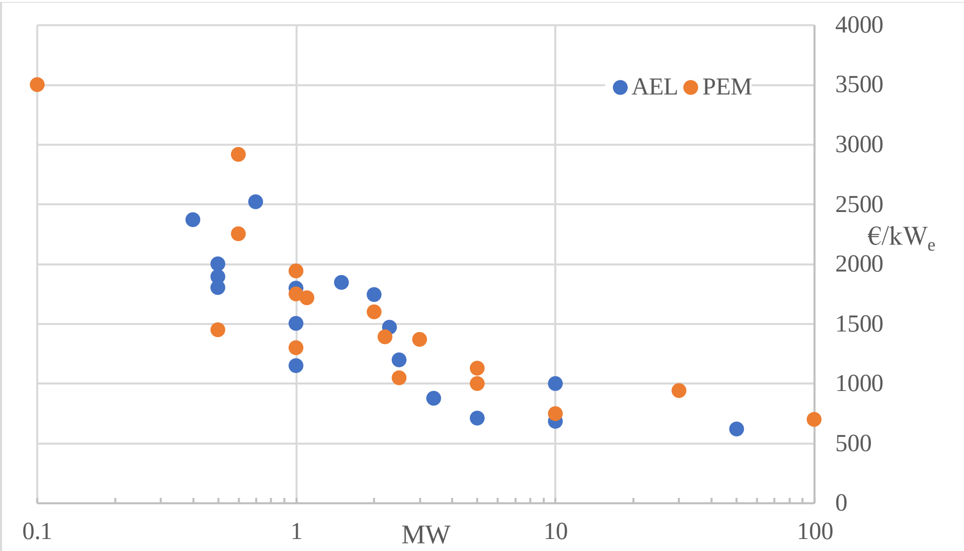


Figure 40. AEL and PEM electrolyser costs based on nominal power. Data from (Zauner et al. 2019, 13).

As it can be noted, scaling can have benefits in cost reduction. However, electrolyser costs can vary between different manufacturers so actual costs will always be project specific.

4.3 Methanation reactor costs

Similarly to electrolysers, methanation reactors have not yet reached a fully commercialised status in terms of PtX application and thus investment costs can be very uncertain due to lack of data. Furthermore, the reactor design and methanation technology together with auxiliary equipment will have an impact on the installation costs. Typically, the investment cost is expressed as €/kW$_{SNG}$ which is based on the output (CH_4) of the methanation reactor. (van Leeuwen, Zauner 2018, 20)

The following figure illustrates literature values for investment costs for biological and catalytic methanation reactors.

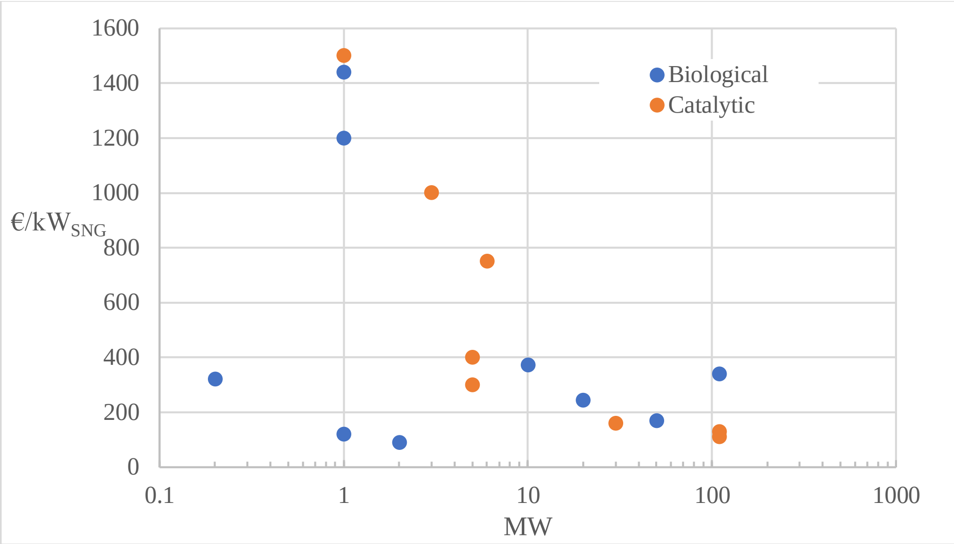


Figure 41. Biological and catalytic methanation reactor investment costs based on SNG output. Data from (Zauner et al. 2019, 20).

The largest cost share of the methanation reactors is the BoP where it represents approx. 50 % of the investment costs for both technologies. The reactor itself is approx. 20 % of the investment costs. The rest is covered by the electrical installation and gas conditioning. (Zauner et al. 2019)

4.4 Carbon capture costs

CO_2 is the main feedstock for producing hydrocarbon-based e-fuels, so the carbon capture costs are typically accounted in the fuel production costs. The cost of carbon capture is related to the CO_2 concentration of the flue gas. Lower concentrations typically increase the costs due to higher energy requirements for the capture process. The following table summarises levelized cost ranges for different CO_2 sources.

Table 12. Levelized costs of carbon capture from different CO_2 sources.

CO_2 source	**CO_2 concentration in flue gas [1] (Except DAC)**	**Cost of carbon capture [€/ton$_{CO2}$] [2]**
Direct Air Capture (DAC)	~ 416 ppm in air [3]	127 – 324
Power generation	3 – 14 %	47 – 95
Cement	15 – 30 %	57 – 114
Iron and steel	21 – 27 %	38 – 95
Natural gas processing	96 – 100 %	14 – 24

Note. Data collected from ([1]: IEA 2019, 32; [2]: IEA 2021b; [3]: NOAA 2022). Cost data converted from USD to EUR. [3]: 2021 annual mean value, ppm = parts per million.

Naturally, variations related to carbon capture technology also plays a role as it can be seen on the wide ranges in costs. The typical CO_2 concentration ranges from EU WtE plants is approx. 10 – 12 % in flue gases (IEAGHG 2020, 63). Thus, it can be expected that the carbon capture costs are in the similar range for WtE plants than for power generation.

The capture costs typically do not include long term storage costs. Considering ship transport to the Northern Lights project, Bjerketvedt et al. (2022, 12) analysed the transport chain for delivering CO_2 to the permanent storage site and the costs were approx. 32.4 €/ton for a 15 bar transport chain.

4.5 Hydrogen compression and pressure vessels

The CAPEX data for hydrogen compressors is lacking and they are dependent on the manufacturer and compression parameters. The Nexant report (2008, 73) developed a relationship based on 2-stage reciprocating compressor vendor cost data and compressor motor rating. The relationship was further adjusted by Christensen (2020, 20) to give CAPEX information in 2020 costs. The following equation describes the CAPEX relationship where compressor motor power P_d (kW$_e$) is from eqn. (7) which is 10 % oversized and the cost is converted from USD to EUR.

$$\text{CAPEX}_{\text{compressor}} = (19207 \times (P_d \times 1.1)^{0.6089} \times 1.19) \times 0.9476 \tag{14}$$

The equation yields an approximate cost of 745 887 € for a 304 kWe 2-stage compressor with 178 kg/h hydrogen flow and a compression ratio of 25. This would result in approx. 0.52 €/kg$_{H2}$ cost by assuming 1424 ton of annual hydrogen production. Although it is a rough estimation of the compressor costs, it implies the significance on the cost of hydrogen compressors when compression is required for storage purposes.

Pressure vessel costs differ between the type of the storage vessels (I-IV) due to materials used and storage pressures. Parks et al. (2014, 39) estimated that 250 bar storage vessels costs would be around 450 \$/kg$_{H2}$ (~ 426 €/kg$_{H2}$) and for high pressure (875 bar) vessels the estimates were 1100 \$/kg$_{H2}$ (~ 1042 €/kg$_{H2}$) for type II and 940 \$/kg$_{H2}$ (~ 891 €/kg$_{H2}$) for type IV. The higher costs for type II with similar pressure levels as type IV could be due to material costs at the time of evaluation since more steel is needed for the heavier type II vessel. The below figure illustrates other literature values for different pressure levels.

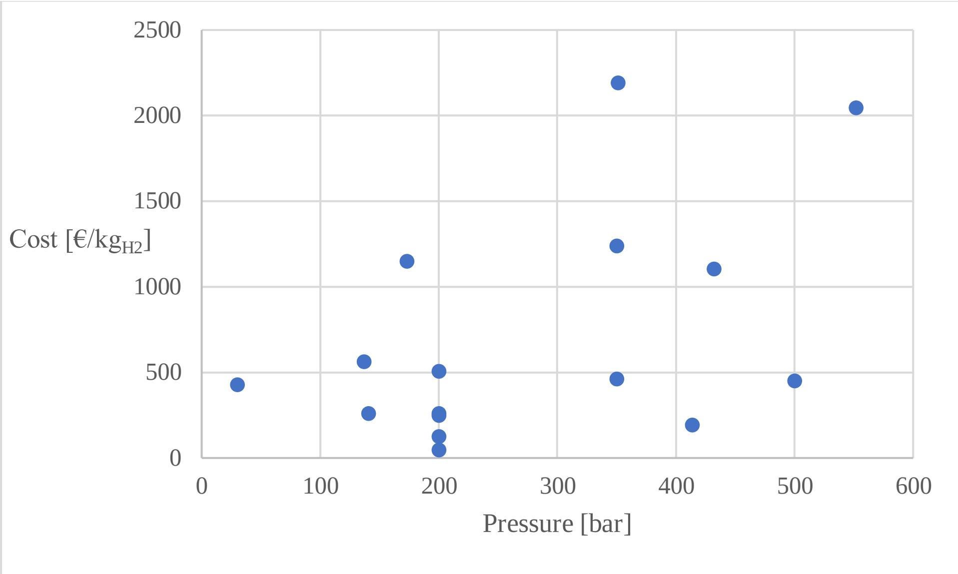


Figure 42. Hydrogen storage vessel costs as a function of pressure. Data from (van Leeuwen, Zauner 2018)

The above literature values were not indicated based on pressure vessel types and some were estimated based on ranged reference values. As it can be seen, the costs for pressure vessels can vary significantly even across similar pressure levels.

4.6 Pipeline costs

The costs for pipeline installation depend on the material, labour, rights of way as well as other miscellaneous costs. Pipeline costs are therefore very specific depending on the region.

Several reports have defined equations which give an approximation of the installation costs in relation to the pipeline diameter. The Nexant report (2008, 42) derived hydrogen pipeline costs based on a regression analysis of US natural gas pipeline costs. From Europe, Baufume´ et al. (2013, 9) developed the diameter-based cost indications from the experience of the German natural gas pipelines where costs ranged from 401 – 490 k€/km for distribution and 433 – 705 k€/km for transmission pipelines.

Distribution pipelines within an urban region would face increased costs due to complexity of installation. Urban area distribution pipelines were approximated as 550 k€/km for hydrogen and 500 k€/km for methane by van Leeuwen and Zander (2018, 30).

In comparison to pipeline delivery, investment costs for a 880 kg CGH_2 tube trailer can be around 500 k€ which is based on the reported production cost by James (2020, 11) by assuming 20 % company markup and converted from USD to EUR.

Although, initial CAPEX investment is lower on the tube trailer delivery option, pipeline delivery of hydrogen can be attractive if there is a need for transporting large quantities of hydrogen to e.g. hydrogen dispensing stations. Actual delivery costs will depend on required delivery nodes and quantity.

4.7 District heat integration and oxygen market

The use of surplus heat from e.g. an electrolyser is possible if the plant joins to an open district heating network where waste heat can be fed to the district heating network. Via personal communication (2022) with a local district heating network provider, the temperature levels are the limiting factor. The waste heat feed temperature levels should be primed to approx. 70 – 75 °C in summertime and should follow seasonal variations. The evaluation of waste head feed suitability is analysed case by case. The reference price for waste purchase is approx. 23 €/MWh.

Selling the oxygen generated by the electrolysis process is another additional revenue source if suitable consumers are located nearby. The amount of total industrial oxygen production in 2020 was approx. 1.62 Mton and the total value of the sold oxygen was approx. 75.6 M€ in 2020. (OSF 2020) This results in approx. 46.7 €/ton value for oxygen. Electrolysers are not equipped by default to capture oxygen so additional equipment is needed for this purpose. However, the cost of oxygen capture is very limited. Van Leeuwen and Zauner (2018, 33) found an investment cost of approx. 20.5 k€ for oxygen capture for an electrolyser.

4.8 Levelized cost of X

The levelized costs of energy is a common metric to compare different energy production costs during the lifetime of the plant or project. The levelized costs can be interpreted as the average price needed for reaching break even when considering all expenditures that occur during the lifetime of the installation. The calculation method divides the sum of the yearly discounted expenditures and sum of the discounted yearly energy production, resulting in the average levelized costs during the lifetime. (IEA 2020b, 34, 35)

The methodology can be adapted to PtX applications to define the cost metrics for producing the X product. The levelized cost of hydrogen (LCOH) can thus be expressed as follows. (FCHO 2021)

$$\text{LCOH [€/kg]} = \frac{I_0 + \sum_{t=1}^{n} \frac{CAPEX_t + OPEX_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{H_{2\,t}}{(1+r)^t}} \tag{15}$$

Where:

I_0	Investment expenditure in year 0 [€]
n	Lifetime of the installation [years]
$CAPEX_t$	CAPEX in year *t* [€]
$OPEX_t$	OPEX in year *t* [€]
r	Discount rate [%]
$H_{2\,t}$	Hydrogen production in year *t* [kg]

Similarly, the equation (15) can be used to assess the production costs of SNG, where it is denoted as the levelized cost of synthetic natural gas (LCOSNG) which is typically expressed as €/MWh_{SNG} based on the LHV. CAPEX at year t includes the replacement costs of electrolyser stacks and yearly OPEX will include fixed operational costs, electricity costs etc. Section 6.1 will describe the assumptions used in this work.

5 PtX ecosystem in Vaasa region

This section will describe the main results from stakeholder interviews. Based on the interview results, the off-taker locations and main product and side stream utilisation are discussed. Furthermore, the scope of this thesis was built up upon the findings of the interviews.

A PtX ecosystem is defined in this work as a network of companies or other actors that creates an integrated technological system for power-to-x business. It is derived from the term business ecosystem, which describes a network of organizations which together create a holistic system to provide value for customers. (Makinen, Dedehayir 2012)

5.1 Key stakeholder interviews

The stakeholder interviews were held during November – December of 2021. The purpose was to map out the potential local off-takers of different PtX products and side streams as well as the drivers and roles of different stakeholders. In addition, uncovering the tacit knowledge of the experts was another target. The participants were selected based on their involvement in PtX related projects and to cover some of the sectors which could be part of a PtX ecosystem. A total of 10 interviewees were invited and 9 were able to participate. The participants and their company categorisations are described in the following table.

Table 13. Expert survey group descriptions.

Interviewee position description	Company category	Date of interview
Senior management	CO_2 source	5.11.2021
Mid-level management	CO_2 source	5.11.2021
Mid-level management	Electricity provider	18.11.2021
Mid-level management	Equipment supplier A	19.11.2021
Senior management	Electricity provider	25.11.2021
Senior management	Equipment supplier B	29.11.2021
Specialist	City	30.11.2021
Mid-level management	City	3.12.2021
Mid-level management	Equipment supplier A	16.12.2021

The interview method was selected as a semi-structured interview, where predefined themes were presented and discussed. A semi-structured interview suits a project where the research design is clarified during the process based on the responses and follow-ups (Eskelinen, Karsikas 2014, 85). The interviews were conducted via Microsoft Teams meetings which were recorded. Meeting notes were prepared by the author and sent to the interviewee for cross-checking. Additional follow-ups were done with some of the participants. The interview form is presented in Appendix 1. The following sections will describe the results per each theme.

5.1.1 Theme 1 – Market potential in Vaasa region

In the first theme, the participants were asked to assess the potential of PtX product and side stream utilisation in Vaasa region. In general, very much interest and recognized potential for PtX technology. However, some uncertainty in the scale of potential. Timeline of present situation until 2030 is a short timeline so pilot and demonstration projects are urgently needed. Electrolyser technology projects and development is still in its infancy in Finland although capability and resources exist for project execution.

Topics were discussed regarding the potential of green hydrogen, synthetic fuels, oxygen side stream, heat side stream and grid service. Green hydrogen received a lot of positive interest; however it suffers from the “chicken and egg” – problem, which means that there is no production if there are no off-takers and vice versa, one must materialise first. Synthetic fuel potential is recognised, however concerns on the costs could potentially hinder acceptance.

Side stream usage was noted as a meaningful way to increase efficiency and potentially gain additional revenue. Grid service was acknowledged as an additional revenue stream, which concerns the down-regulation and up-regulation of the electricity market. PtX could be used in down-regulation and thus increasing electricity consumption while producing hydrogen with water electrolysis. A hybrid plant could participate in up-regulation as X-to-Power (XtP) where hydrogen, or another renewable fuel, is used to produce electricity with fuel cells (FC) or internal combustion engines (ICE).

The following figure summarises the pros and cons from the different topics.

	Green hydrogen	Synthetic fuels	Oxygen side stream	Heat side stream	Grid service (XtP)
Pros	+ Good potential due to Vaasa´s central location and concentration of energy companies + Good wind resources and expectation of growth of wind power generation + Seen as important tool for flexible operation against the electricity market (imbalance settlement) + Recognized as energy storage medium + Possible blending with other fuels + Down-regulation bidding tool	+ Methane use in many forms in Vaasa area + Potential as drop-in fuels + Requires stable CO2 source (Green carbon) + LNG terminal will be built to the port of Vaasa	+ Battery manufacturing could utilise at a large scale if GigaVaasa plans materialize + Oxy-fuel combustion	+ Possible to store in Vaskiluoto seasonal heat storage + Use/integrate in existing DH network + Waste heat recovery increases plant efficiency + DH demand will likely increase due to Vaasa´s expected population growth + Phasing out coal CHP plants by 2030 increases interest in alternative heat generation	+ Seen as important tool for flexible power generation and demand response + Up-regulation bidding tool + Dynamic response. Imbalance settlement currently 1 hr, 15 min in the future. 15 min settlement time drives development for rapid demand response
Cons	- No fully developed or large scale off-takers for H2 in place - Missing infrastructure (storage, pipeline, fuelling stations etc.) - “Chicken and egg” - problem	- Cost of synthesis products, further synthesizing H2 to multiple hydrocarbon alternatives reduces efficiency and increases costs. - Requires stable CO2 source (Black carbon)	- If no large scale consumer nearby (uncertainty of GigaVaasa battery manufacturing), storage and transport might not be feasible	- If not used, efficiency gains are lost.	- Dynamic response needed from Electrolyser / FC / ICE plant. Imbalance settlement currently 1 hr, 15 min in the future. - Finnish electricity market structure is so that negative electricity prices are not typical. With all costs included, never below 0 €.

Figure 43. Pros and cons of different topics from theme 1.

Considering the timeline, some key milestones were noted. The timeline is illustrated in the following figure.

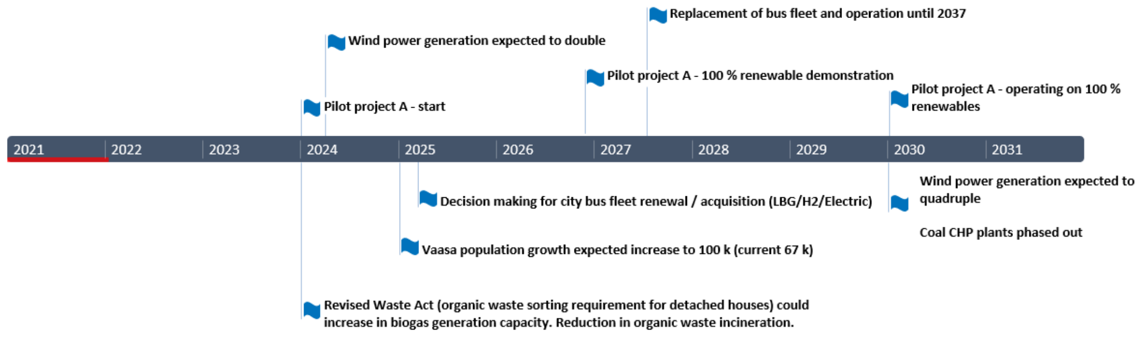


Figure 44. Timeline with significant milestones regarding PtX ecosystem.

As it can be seen, some major actions are expected in the coming years which could drive up the potential of PtX applications.

5.1.1.1 Synthetic fuels adoption

Interviewees were asked to rate different e-fuels in a priority for the application in Vaasa region. The following figure summarises the responses.

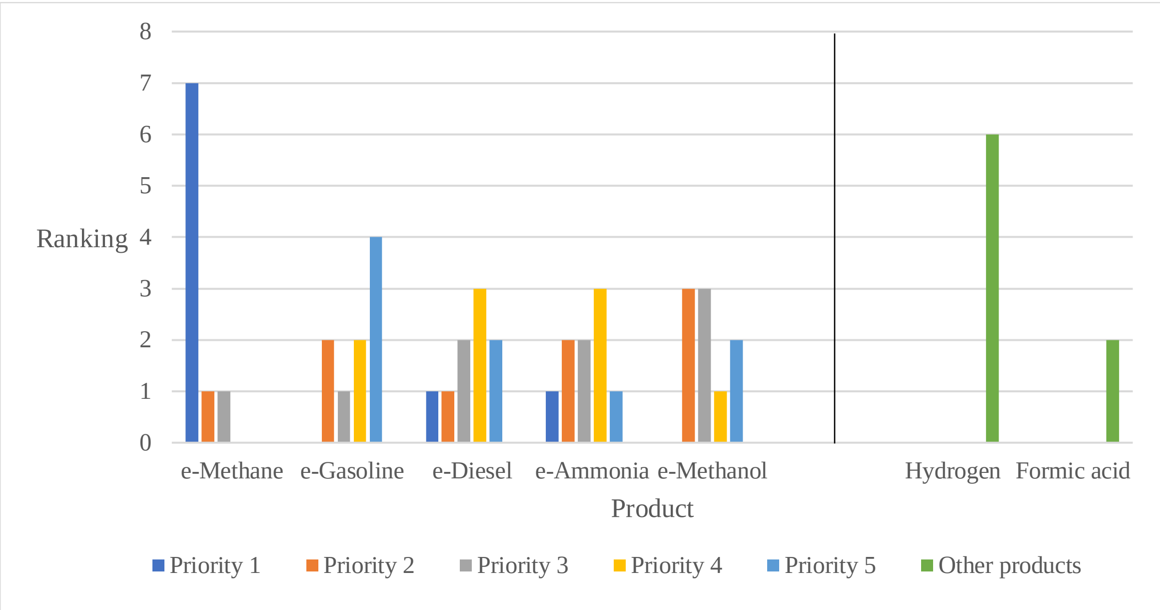


Figure 45. E-fuels priority ranking according to interview responses.

CO_2 as a feedstock from a CHP plant could be utilised to produce e-fuels. Methane was considered the highest ranking e-fuel from questionnaire which was based on the available off-takers and potential for quick adoption. The need for methane is approx. 600 t/a for city´s gas fuelled buses and 1000 t/a for natural gas fuelled ferry. Additionally, approx. 1000 personal vehicles use gas dispensers annually.

Hydrogen as recognised as another major product, however limited consumption at this stage expected. Possible blending with e.g. methane could be considered. Conventional fuels on the other hand had the lowest priority, however consumer base and infrastructure exist. Cost of synthetic alternatives plays a key factor.

Methanol received the most votes for the 2nd priority which could be used in the marine sector. Diesel infrastructure and engines could support with relatively low modifications. Ammonia was recognised as a marine sector fuel and chemical industry feedstock. Formic acid was mentioned as a potential synthesis product for chemical industry raw material with an existing value chain.

5.1.1.2 Infrastructure

In terms of sector coupling, the electricity and heating network is already coupled due to district heating network and CHP plants. Additional heat source connection to the network would enable a more distributed heating network.

The sector coupling to transport sector, however, is lacking. It would require transportation infrastructure development with close cooperation with the city and transport companies. Logistic companies have typically large (and expensive) fleets, so they are very much interested in what possibilities are available in the area.

Hydrogen infrastructure is missing and natural gas infrastructure is generally under developed. However, an LNG terminal will be constructed so it might prompt additional gas infrastructure development. Offtake agreements could facilitate the development of the infrastructure as well. Large scale hydrogen storage options are not readily available at this stage.

5.1.2 Theme 2 – Value drivers for a business case

The second theme was based around the value drivers that PtX applications could bring to the stakeholder. The results were categorised into “hard” and “soft” values. Hard values represent a more business value i.e. cash flow or technical values. Soft values represent the more societal or marketing-based values.

Table 14. Value driver categorisation from different stakeholders.

	Hard values	Soft values
CO_2 source	CO_2 off-taker and value chain for CO_2 needed for CCU/S in local and international scale. Regional political decisions.	Decarbonisation targets.
Electricity provider	Business case from electricity price fluctuation. Demand response and asset flexibility. Efficiency increase in connection with CAPEX & OPEX.	Carbon neutrality target by 2030 or earlier
Equipment supplier B	Hydrogen economy sits well in company strategy. Differentiating from competition. Increasing efficiency on a system level.	Sustainability / circular economy in own operations and assisting customers in achieving sustainability ambitions.
City	Implementing new technologies such as PtX applications fits the city´s (and its subsidiaries) strategy and branding plans.	Promoting sustainable innovations and the knowledge base is a value point for the city.
Equipment supplier A	Business case value driver is the growth opportunity that PtX business could generate. Incentives on investing into sustainable products is seen necessary. Identification of customers who are is willing to pay a premium for sustainable products.	Decarbonisation targets are a value point for the company.

The values were suitably represented in both categories. Naturally, harder values dominate in a newer technical field where business potential is closely examined. It implies the importance of achieving a positive business case for the market acceptance of PtX applications.

5.1.3 Theme 3 – Roles

The third theme was based around the identification of different roles of the possible PtX ecosystem members. The interviewees assessed on where their part would fit and each of the role possibilities were grouped into main roles and sub roles.

Main roles are the roles that would best fit their current ambitions or portfolio. Sub roles are the roles that would be of interest in addition to the main role. The role identifications are illustrated in the following figure

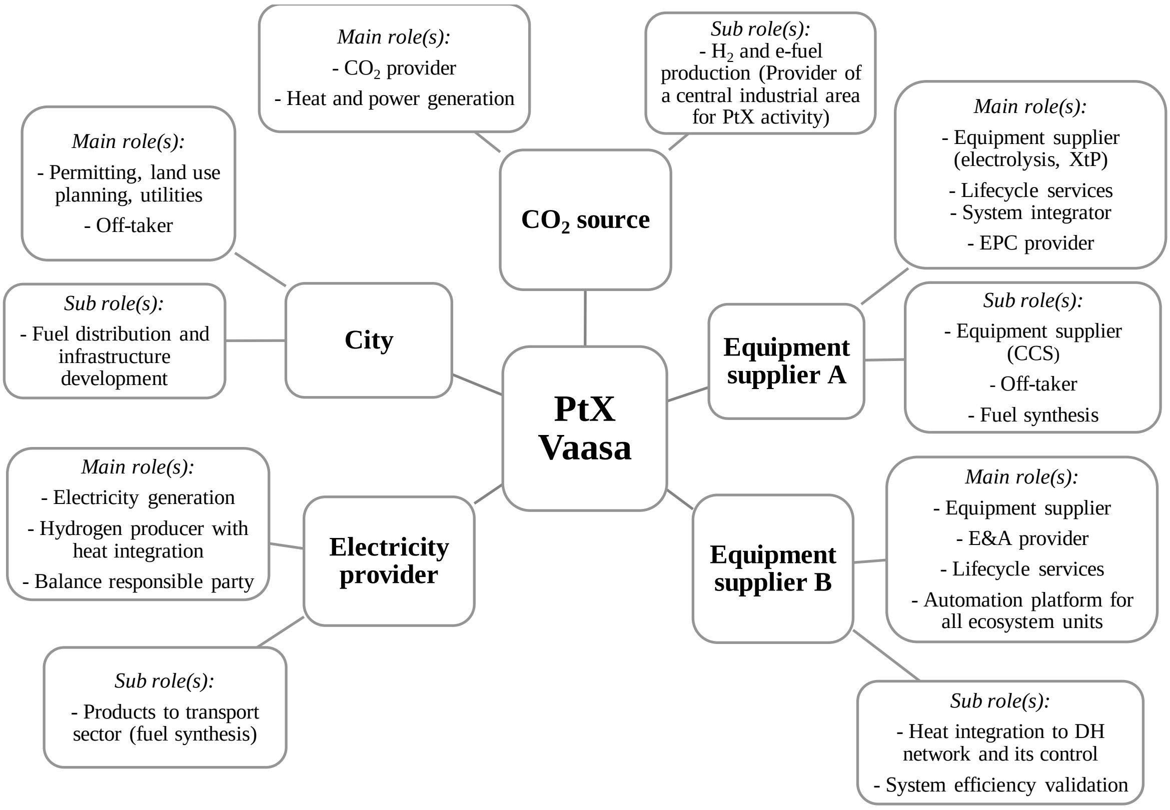


Figure 46. Role descriptions of the different PtX ecosystem members. Engineering Procurement and Construction (EPC). Electrical and Automation (E&A).

The key role for each member can be seen in the main role descriptions and it represents their current or possible portfolio of products and services. The exploration of sub roles reflects some of the additional expansion interests; however, a common denominator is that it must make sense business wise to pursue additional fields outside their “comfort zone”, at least on the actors operating on the private sector.

5.1.4 Theme 4 – Regulation drivers

The final theme was based around the regulation drivers that could affect members own operations or the field of PtX. The key regulation driver elements are listed below.

Electricity provider:

- EU ETS seen as a driver.
- Incentives/subsidies/feed-in-tariffs for e.g. green hydrogen production.

- PtX plant interpretation in terms of taxation would need further investigation and clarification. Excessive taxation should be avoided.
- Guarantee of origin / certification scheme would be preferred.

CO_2 source:

- 2030 carbon neutrality target is approaching very soon and the need for clear regulation is essential to get piloting projects and large-scale projects ongoing.
- Specific agreements for the sectors covered by ESR would concentrate on local efforts for reducing emissions and funding would stay within the region and thus generating opportunities locally.
- Maritime ETS and emission reductions requirements for transport seen as an important driver so PtX products will have an important role in the emissions reduction efforts where electrification is not seen feasible.
- High price on carbon (ETS) is also seen as a driving factor although the costs can be included in the energy price which will be eventually paid by the consumers.

Equipment supplier A:

- Regulation is seen as beneficial for development. It has been driving development throughout the years. Influencing regulation is also seen important.
- ETS will influence customers. ETS can be seen as a guiding instrument for transition, however, the price of carbon needs to be sufficient or else it will not drive change.
- Regulation will drive development but added value could be found by identifying a customer/segment with a positive business case where development can be accelerated by even going further than regulation.
- RED 2 and its revision is not yet formally finalized. Too restrictive approach from regulation could potentially hinder development.
- Industrial companies announce their own commitment and targets for decarbonisation so regulation should assist and steer the development, however it seems that regulation is a bit lagging.

- Carbon emission curtailment via market-based mechanisms such as ETS will drive the development towards low emission alternatives and CCS/U. Subsidies and financing instruments will assist the development as well, however the market will drive the change eventually.

Equipment supplier B:

- Regulation effects indirectly or it is considered neutral.
- Regulation that decreases combustion processes could be seen in the increase of heat pumps and hydrogen production.
- Regulation steers development direction. Direction can be guided by either regulating an aspect or providing incentives for development. Either way it is seen as positive when investments are getting supported.

City / off-takers:

- CO_2 provider is driven by regulation. CCS/U alternatives will likely need to be implemented to continue operation.
- National targets and EU´s directives for decarbonising the transport sector will drive the transition from fossil fuel-based options to alternative solutions. This affects the city's fleet of vehicles and their future acquisitions
- EU decarbonisation targets will drive the development of PtX technology (100 carbon neutral cities, EU wide decarbonisation, natural gas dependency detachment).
- Distribution obligations and taxes effect consumer prices already. CNG price determined by the international market price properties of carbon and crude oil together with other parameters. Regulation will increasingly affect gas prices.
- Over regulation of e.g. PtX products should be avoided. They should not be treated the same way as fossil fuel-based products. Private sector will be hesitant to invest if regulation is not clear.
- Increasing the reach of ETS will affect the consumer prices since the cost of carbon will be most likely priced in the product(s).

- FuelEU Maritime regulation will likely increase the adoption of alternative fuels and environmentally friendly options in the maritime sector.

Overall, regulation aspects can be seen necessary and it is recognised as a guiding element. However, clarity of regulations is needed as it influences business cases and any (offtake) agreements as well as investment decisions.

5.2 Main products and side stream utilisation and handling

Currently, there were no large-scale off-takers for hydrogen identified, and thus the main PtX product would be to convert hydrogen into methane which can be used in the transport sector. CO_2 for synthesis feedstock can be sourced locally from a CHP plant as well as the steam for a SOEC electrolyser.

Waste heat side stream could be integrated to the local district heating network and be used to charge the underground heat storage at Vaskiluoto. The heat storage is converted from old diesel storages and can withhold approx. 7000 – 9000 MWh of energy for district heating purposes. (Vaasan Sähkö 2019) Provided that the electrolyser is powered with renewable electricity, the waste heat could be categorised as renewable as well.

The electrolyser oxygen side stream could be utilised by the battery manufacturing industry. Oxygen is used in the production process of cathode active materials (CAM) and specifically in the calcination of lithium hydroxide and precursor mixture (Ramboll 2021, 30). An environmental impact assessment was prepared for CAM manufacturing location alternatives where Vaasa was one of the possible locations. In addition, the manufacturing process requires steam, which can be produced with a natural gas boiler (Ramboll 2021, 32). Three different manufacturing alternatives were evaluated and their production capacities alongside their estimated oxygen and natural gas need is presented in the following table.

Table 15. CAM manufacturing oxygen and natural gas need. (Ramboll 2021, 30, 32)

	CAM manufacturing capacity alternatives		
	20 000 t/a	**60 000 t/a**	**120 000 t/a**
Oxygen [t/a]	80 000	240 000	480 000
Natural gas [t/a]	4 300	13 000	26 000

Note. Oxygen purity requirement of 93 %. Natural gas converted from m^3/a with density at STP.

As it can be seen, the need for oxygen and natural gas is significant. As a replacement for natural gas, SNG could be used for the steam generation process.

There are no hazardous waste incineration plants in Vaasa area so the reclaimer waste, as discussed in chapter 2.3.2.1, must be transported elsewhere. Currently, Fortum Waste Solutions plant in Riihimäki is the only waste incineration plant in Finland which has permits for hazardous waste incineration. (Bröckl et al. 2021, 23)

The following figure illustrates the potential geographical locations of PtX applications in Vaasa area.

Figure 47. Indicative locations for PtX alternatives and off-takers in Vaasa area.

The locations are within approx. 10 km radius from the Vaasa centre which requires logistic arrangements for supplying products.

6 Case study

This section will present the case study for the regional power-to-X concept. The core techno-economic model is presented as well as the assumptions and methodology for the overall techno-economic assessment.

6.1 Techno-economic model

The following figure illustrates the techno-economic model used for the case study.

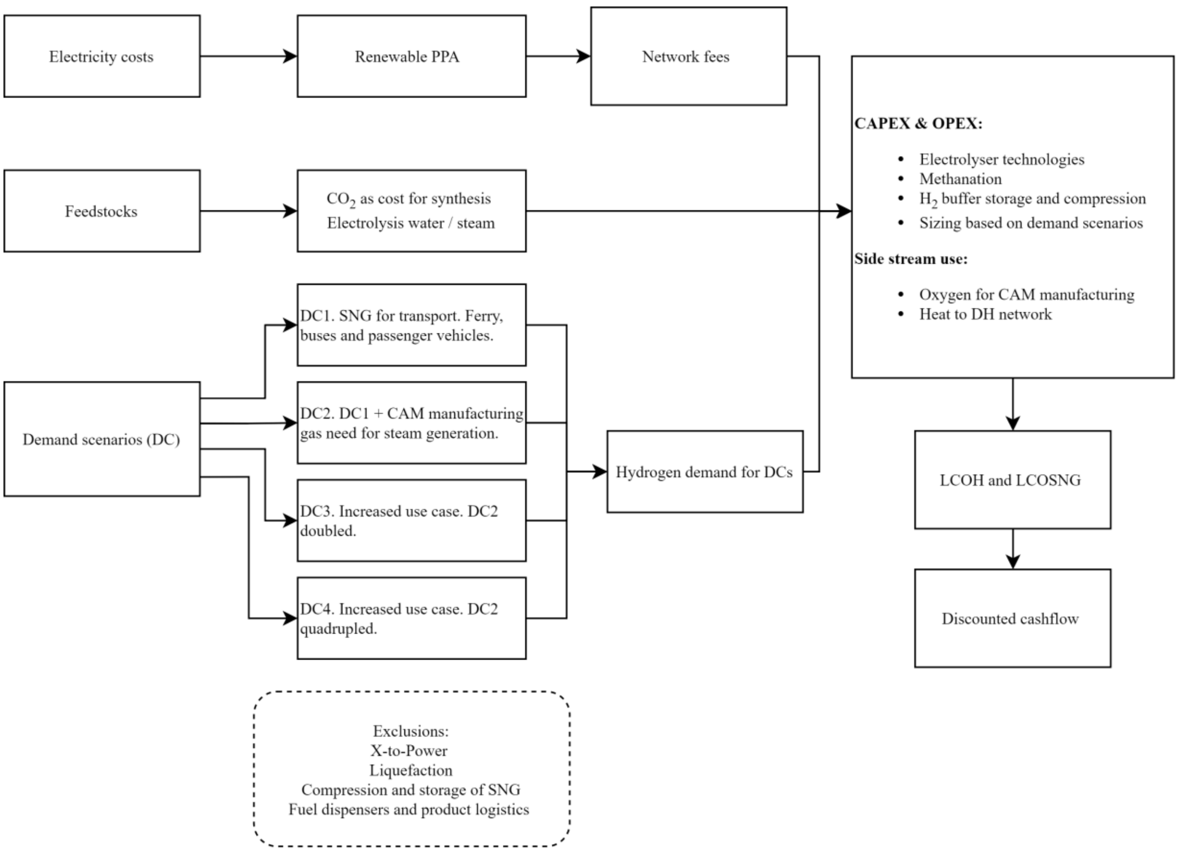


Figure 48. Techno-economic model parameters.

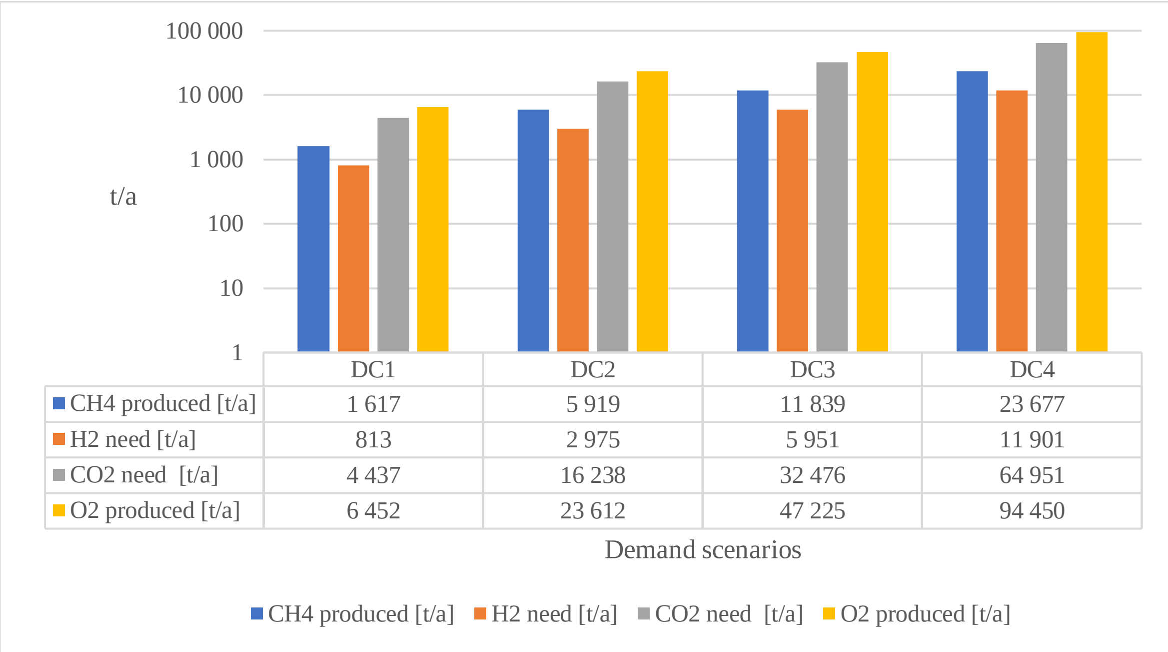
The necessary inputs and outputs were selected based on the potential alternatives for the Vaasa region. Exclusions are set so that the scope of work does not inflate, although also important factors, the focus was set to discover the indicative costs associated in the production of SNG. The following chapters further explains the different core elements for the case study.

6.2 Demand scenarios

The demand scenarios are based on the current approximate demand for natural gas in Vaasa region. The following descriptions apply to the demand scenarios:

- DC1. The current demand for gas fuelled transportation sector for the local ferry, buses and passenger vehicles.
- DC2. Gas fuelled transportation sector need and CAM manufacturing gas need for the smallest manufacturing capacity, see Table 15.
- DC3. An increased demand scenario which assumes that the gas need is doubled from DC2.
- DC4. An increased demand scenario which assumes that the gas need is quadrupled from DC2.

The amounts for different feedstocks and products are based on the stoichiometric mass balances which was described in Figure 22. The following figure illustrates the annual amounts for the different demand scenarios.



	DC1	DC2	DC3	DC4
CH4 produced [t/a]	1 617	5 919	11 839	23 677
H2 need [t/a]	813	2 975	5 951	11 901
CO2 need [t/a]	4 437	16 238	32 476	64 951
O2 produced [t/a]	6 452	23 612	47 225	94 450

Figure 49. Annual production and feedstock requirements for different demand scenarios.

The mass balances are based on ideal conversion of feedstocks, so in practice there will be deviations. Nevertheless, they give the indicative data for further evaluation.

6.3 Methanation plant sizing and operational assumptions

The electrolyser sizing is based on the demand scenarios annual hydrogen demand in kg (H_2), specific system level consumption in kWh/kg (SC_{elec}) and annual full load hours (FLH). Electrolyser technologies chosen for this evaluation are AEL and SOEC. AEL was selected based on its potential to be a likely candidate for an actual project due its maturity. SOEC was chosen to represent a potential new technology with promising efficiency which can be coupled to a CHP plant. The following equation is used to determine the indicative nameplate rating (P_{elec}) for the electrolyser in kW_e that is used for electrolyser CAPEX evaluation.

$$P_{elec} = \frac{H_2 \times SC_{elec}}{FLH} \tag{16}$$

Similarly, the catalytic methanation equipment sizing for CAPEX evaluation is based on the demand scenarios annual production need of SNG in kg, the LHV of methane in kWh/kg[6] and FLH. Catalytic methanation is selected for this case study due to its space saving potential and maturity level. The following equation is used to determine the indicative rating (P_{SNG}) in kW_{SNG} for the methanation unit.

$$P_{SNG} = \frac{SNG \times LHV}{FLH} \tag{17}$$

In addition, the methanation plant will include a 1-hour hydrogen buffer storage to accommodate transient operations for each scenario. The compressor sizing is based on the hourly hydrogen production and equations (6) and (7) with associated storage capacity and compression need. The storage capacities are 102 kg, 372 kg, 774 kg and 1488 kg for the demand scenarios 1 – 4 respectively.

The annual usable waste heat amount for additional revenue is estimated based on the following equation where the half of the remaining energy used for annual hydrogen production is usable heat that can be fed to the district heating network.

[6] LHV in kWh/kg based on 50 MJ/kg and that one kWh contains 3.6 MJ.

$$\text{Waste heat[MWh]} = \frac{\left(SC_{elec} - LHV_{H_2}\right) \times H_2}{1000} \times 0.5 \tag{18}$$

The above equation represents approx. 20 % of the annual electricity consumption for hydrogen production. Waste heat is only utilised in the AEL case. The heat extracted from methanation unit is assumed to be utilised for carbon capture process heat needs. In SOEC case, the heat management utilises all the required heat internally.

Operational data are based on the findings in this work. The operational assumptions are presented in the following table.

Table 16. Operational data assumptions.

Description	**AEL**	**SOEC**	**Based on**
Full load hours [h]	8000		Own assumption
SC_{elec} [kWh/kg]	56	42	See Table 2
Stack lifetime [h]	60000	20000	See Table 2
Degradation rate [%/a]	1	3	See Table 2
Water consumption [l/Nm^3]	1	-	See Table 2
Steam consumption [kg/h/MW]	-	321	Calculated based on Table 2
Operating pressure [bar]	10	1	See Table 2
Compressor / e-motor efficiency [%]	89 / 95		Own assumption
Number of compressor stages	2		Own assumption
Storage pressure [bar]	250		Own assumption
Compressor electricity consumption [kWh/kg]	1.7	3.5	Calculation from eqn. (6) and (7)
Methanation electricity need as [%] of SC_{elec}	6		[1]

Note. [1]: Electricity need based on full load operation. Estimated from (Frank et al. 2018, 11)

The indicative electrolyser, methanation and compressor ratings for each demand scenario are presented in the following figure.

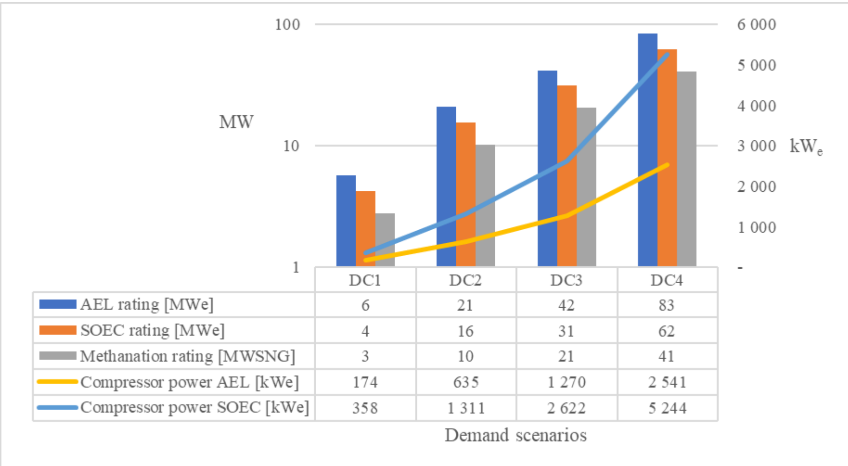


Figure 50. Electrolyser, methanation and compressor ratings for demand scenarios.

The next chapters will present the economic assumptions for the case study.

6.4 Economic assumptions

All costs calculations include no taxes. To take into consideration the scaling effect, the DC1 will be the reference value for other scenarios. The assumptions used in the economic assessment are presented in the following table.

Table 17. CAPEX and OPEX assumptions.

Description	**AEL**	**SOEC**	**Based on**
Electrolyser CAPEX [€/kW]	900	2000	Own assumption, reference cost
Scaling factor electrolyser	0.75		[1]
OPEX fixed [%] of CAPEX	2	2	Own assumption
Stack replacement costs as [%] of CAPEX	50	30	See Figure 39
	Methanation		
Methanation CAPEX [€/kW$_{SNG}$]	300		Own assumption, reference cost
Scaling factor catalytic methanation	0.64		[2]
OPEX fixed [%] of CAPEX	10		[3] Including catalyst replacement
	Compression & storage		
Compressor CAPEX [€]	Depending on DC		Calculation from eqn. (14)
OPEX fixed [%] of CAPEX	2		Own assumption
Pressure vessel cost [€/kg]	400		Own assumption
Note. [1][2][3]: From (Zauner et al. 2019, 13, 20, 37).			

In addition, for plant site preparation, engineering, project management, civil works and miscellaneous indirect costs are assumed to be 20 % from CAPEX for electrolysers and methanation scenarios. Additional variable OPEX assumptions for the methanation plant operation are presented in the following table.

Table 18. Variable OPEX assumptions.

Description	**Cost**	**Based on**
Electricity cost [€/MWh]	50	PPA price and 110 kV transmission tariffs [1]
Water costs [€/m^3]	3.6	Estimated based on [2]
Steam costs* [€/ton]	20	Estimated based on [3]
CO_2 cost for methanation [€/ton]	50	Own assumption
Note. ([1]: EPA 2021; [3]: Pérez-Uresti et al. 2019, 7; [2]: VaasanVesi 2022). * Biomass-based steam cost from [3].		

The following figures summarises the total costs for the PtM plant for different demand scenarios. The scaling effect on initial CAPEX is illustrated as well.

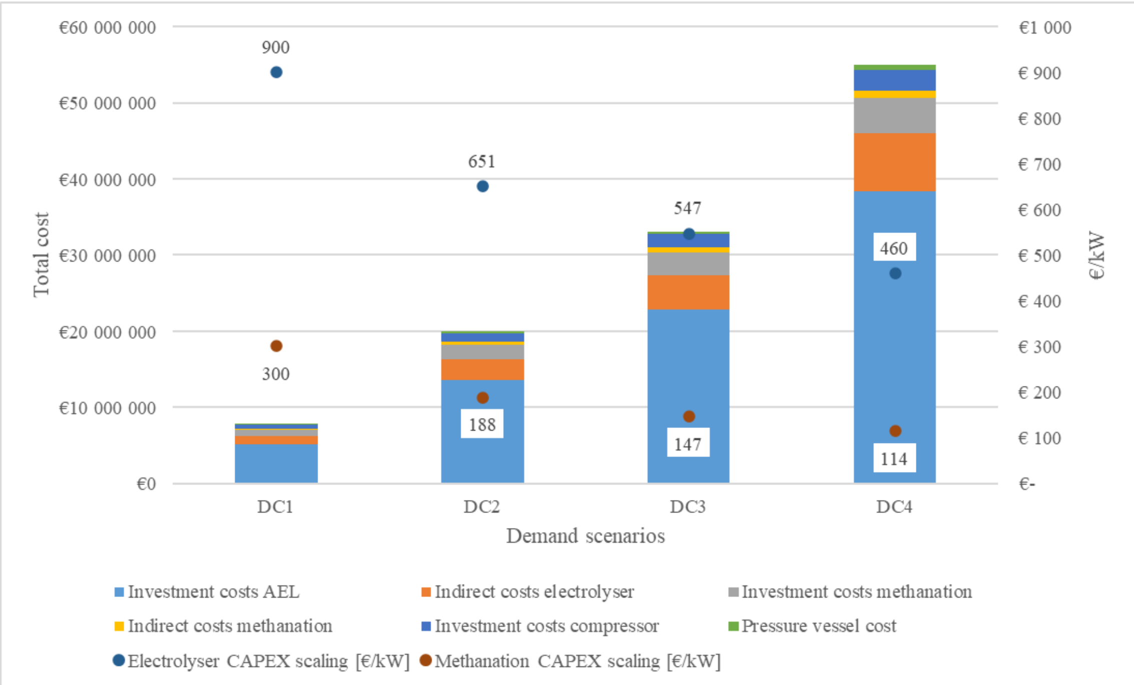


Figure 51. Total investment costs and scaling effect for demand scenarios based on AEL alternative.

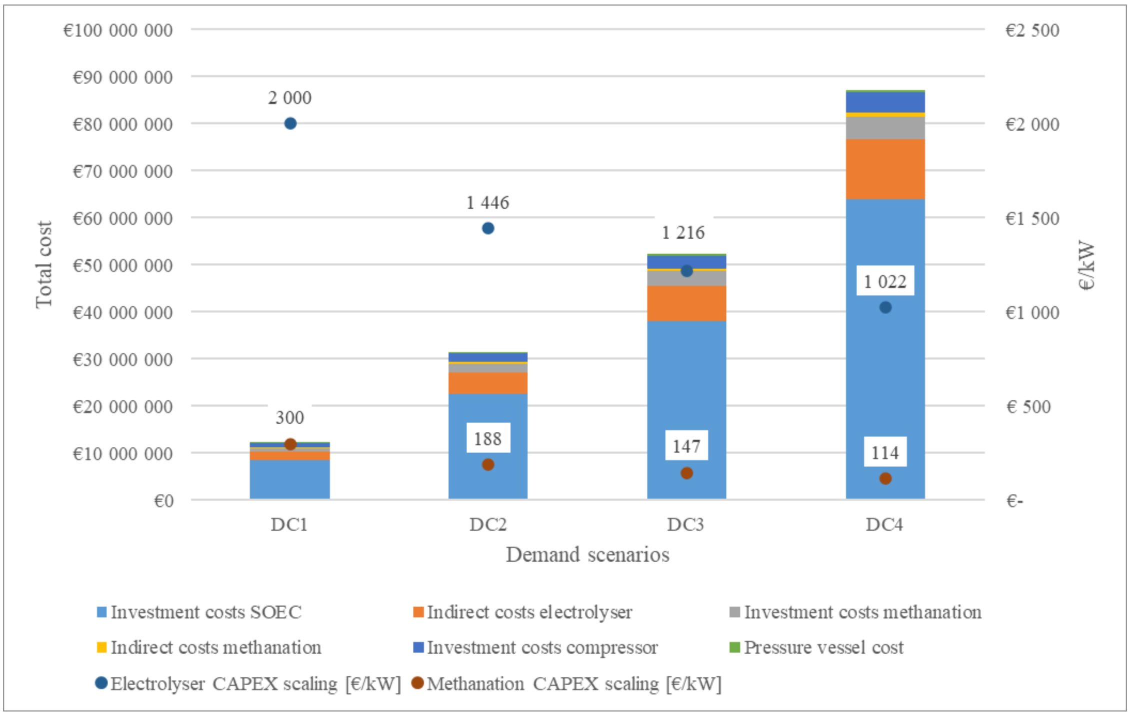


Figure 52. Total investment costs and scaling effect for demand scenarios based on SOEC alternative.

The following figures illustrates the annual OPEX shares for the PtM plant for electrolyser alternatives.

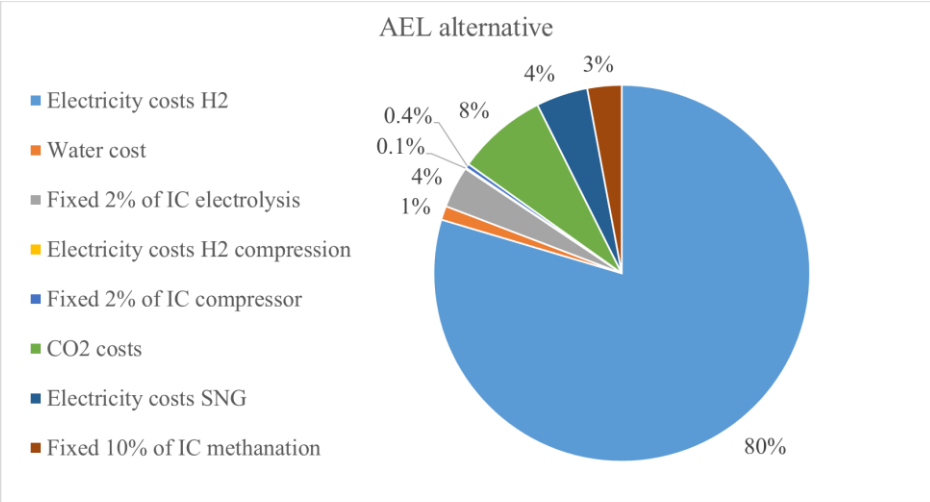


Figure 54. Annual shares of total OPEX for AEL alternative for DC1.
Investment Cost (IC).

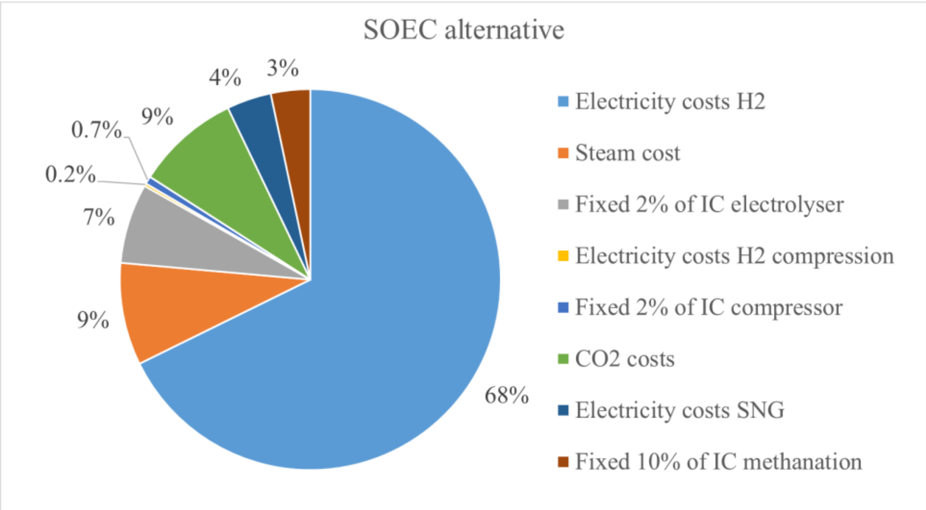


Figure 53. Annual shares of total OPEX for AEL alternative for DC1.

As it can be seen the electricity costs dominate in both alternatives. SOEC steam requirement and its cost is a notable difference between the two technologies. Furthermore, the electrolyser investment costs are a major part of the PtM plant installation costs.

6.5 Discounted cashflow

To evaluate the feasibility of the case study alternatives, a discounted cashflow analysis is used. The method results in the net present value (NPV) in € of the project at the end of its lifetime. A lifetime of 20 years and a discount rate of 7 % is assumed for the economic assessments. The initial investment (I_0) is the base from where present value is calculated with the annual discounted cashflows containing revenues and total expenditures in the examined year. The following equation is used for calculating the NPV.

$$NPV = -I_0 + \sum_{t=1}^{n} \frac{Revenues(t) - Expenditures(t)}{(1+r)^t} \tag{19}$$

To have a feasible project, the NPV should be > 0 €. The revenues for the side streams are assumed to be 40 €/ton for oxygen and 23 €/MWh for waste heat. For SNG revenues, the following table presents the reference prices that are used in the economic feasibility evaluation.

Table 19. Reference sales prices for SNG for feasibility evaluation.

Description	Price	Based on
SNG sales price reference 1 [€/MWh]	145	Natural gas pump price [1]
SNG sales price reference 2 [€/MWh]	109	Biogas pump price [2]
SNG sales price reference 3 [€/MWh]	105	EGIX reference price for natural gas [3]

Note. ([3]: EEX 2022; [1][2]: Gasum 2022). Value added tax is deducted from [1][2]. The European Gas Index (EGIX). May 2022 price for [3].

The economic feasibility is assessed based on the three reference prices and assuming side stream revenues in all cases. Levelized costs for hydrogen and SNG will be evaluated based on chapter 4.8 and will be applied the same lifetime and discount rate as well as the side stream revenues.

7 Results and discussion

This chapter will present the main findings of the thesis. Case study feasibility results are shown first to determine the optimal setup for the Vaasa region. The sensitivity of variable assumptions on the levelized costs is presented as well. The results are then discussed and reflected against the research questions and hypothesis. Lastly, future research topics are suggested.

7.1 Levelized costs of products

The levelized costs for each demand scenario for the electrolyser alternatives are shown in the following figures.

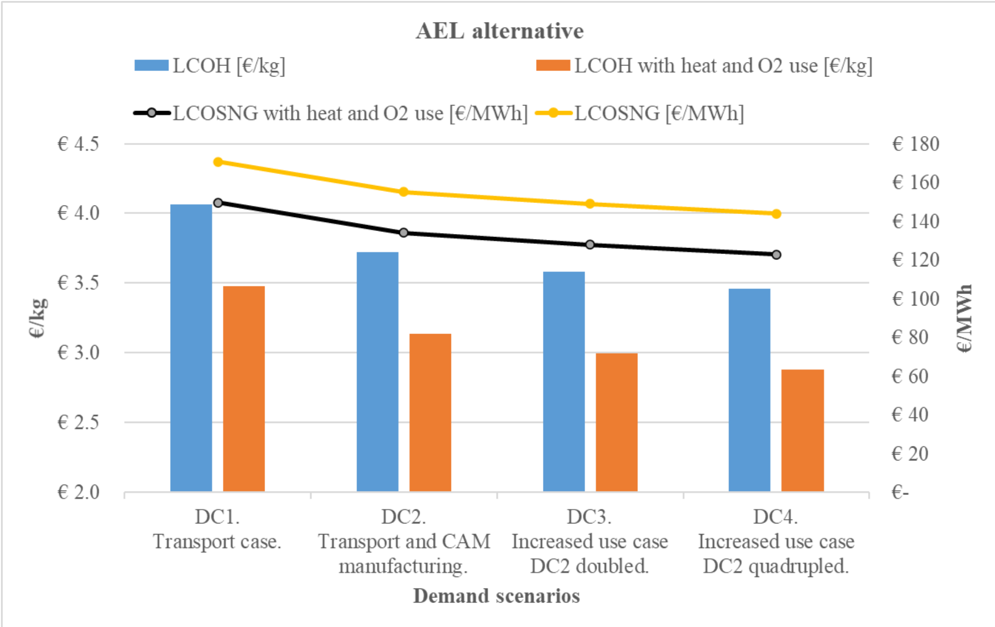


Figure 56. LCOH and LCOSNG for AEL alternative in different demand scenarios.

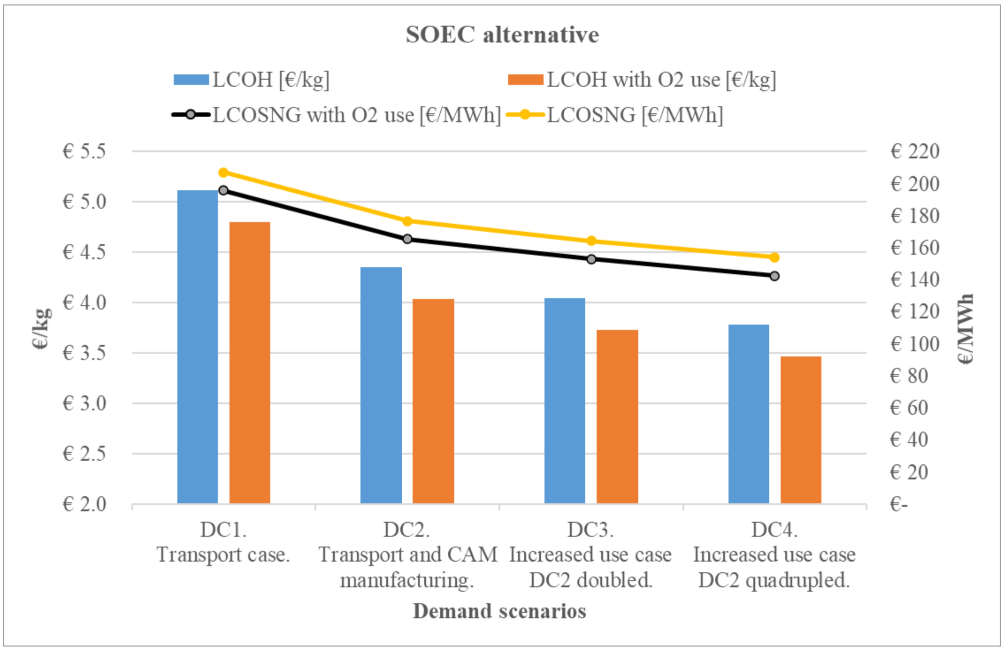


Figure 55. LCOH and LCOSNG for SOEC alternative in different demand scenarios.

The results show that the levelized costs for hydrogen and SNG are lowest for the AEL alternative. Furthermore, the scaling effect reduces the levelized costs. The impact of utilising side stream revenues is noticeable which represent and approximate reduction of levelized costs of 14 – 17 % for hydrogen and 12 – 15 % for SNG in AEL cases. The reduction of oxygen side stream use in SOEC cases represents approx. 6 – 8 % and 6 – 7 % reduction in hydrogen and SNG costs, respectively.

7.1.1 Feasibility of different alternatives

The feasibility of all demand scenarios resulted in negative NPV values for AEL and SOEC cases with sales price references 2 and 3, thus with corresponding SNG pricing, the project alternatives are not feasible. However, with sales price reference 1, the results returned positive NPV results for AEL and SOEC cases that are shown in the following figures.

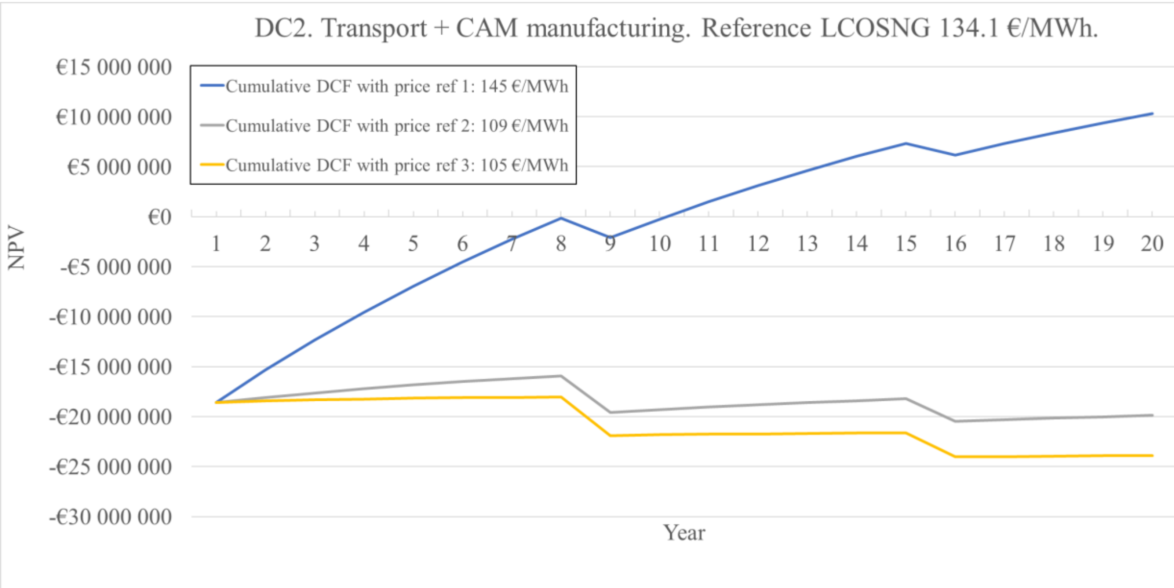


Figure 57. Discounted cashflows (DCF) for price references for AEL DC2 scenario.

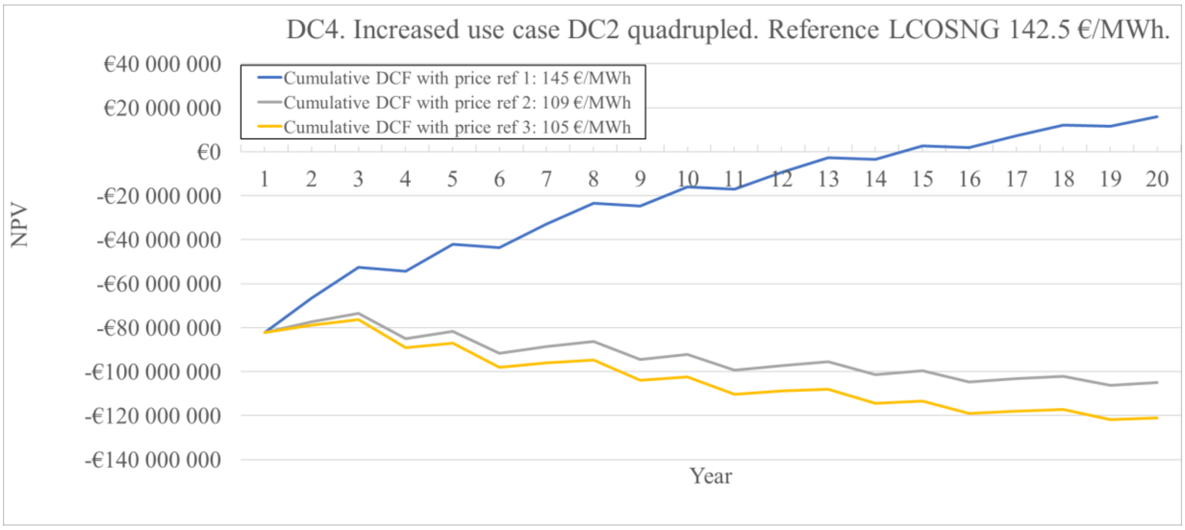


Figure 58. Discounted cashflows (DCF) for price references for SOEC DC4 scenario.

In the case of SOEC, only DC4 returned a positive NPV of approx. 15.3 M€ with sales price reference 1 at the end of the project lifetime, others were severely negative. The payback time is approx. 14.5 years for the SOEC DC4 scenario. The stack exchange costs for both alternatives are reflected in the downwards movement of the discounted cashflow line.

AEL alternative returned positive NPV values from DC2 onwards with price reference 1. The following summarises the results for different DCs:

- DC2. NPV of 11.2 M€ and payback time of approx. 10.1 years.
- DC3. NPV of 32.5 M€ and payback time of approx. 6.5 years.
- DC4. NPV of 81.4 M€ and payback time of approx. 5.2 years.

The discounted cashflows for all scenarios are presented in Appendix 2 for AEL and Appendix 3 for SOEC.

7.1.2 Sensitivity analysis

To illustrate the sensitivity of the assumptions in relation to the levelized costs used in the techno-economic assessments, a one variable sensitivity analysis was done for each scenario. The range of the variable change is illustrated between the parenthesis after the reference assumption. The sensitivity of selected variables is presented in the following figures for AEL.

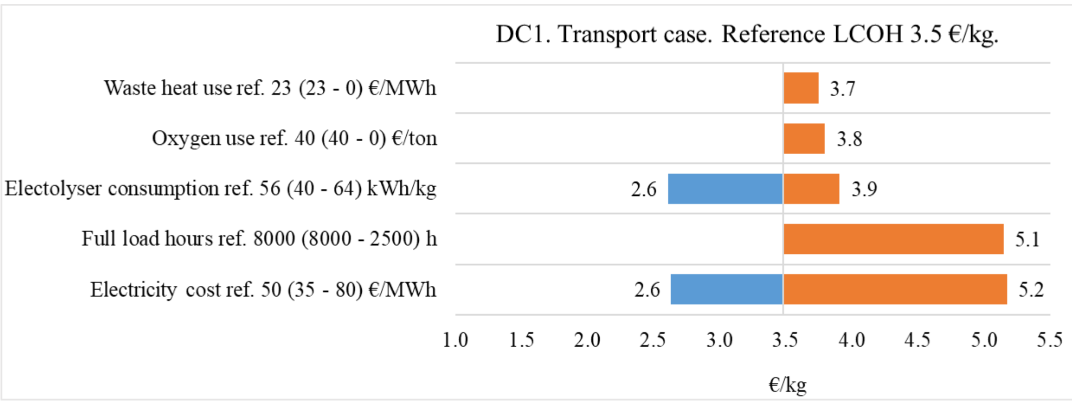


Figure 59. One variable sensitivity analysis of LCOH for AEL DC1 scenario.

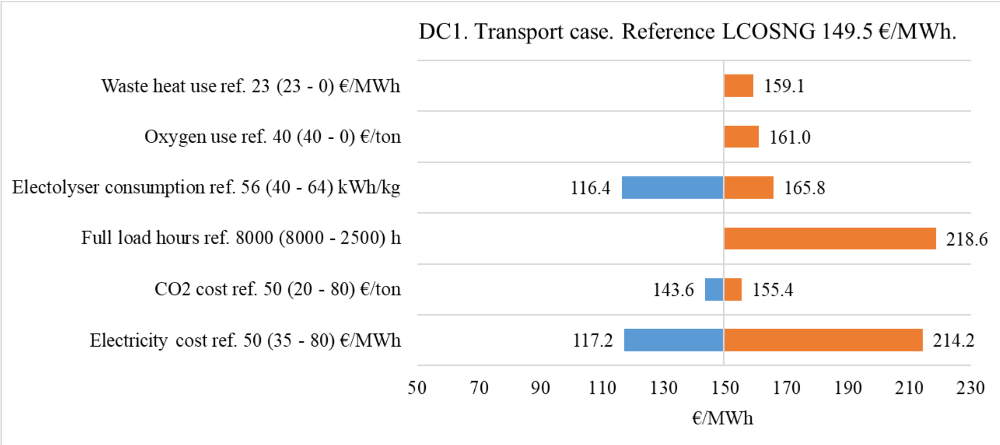


Figure 60. One variable sensitivity analysis of LCOSNG for AEL DC1 scenario.

Similar one variable sensitivity analysis was done for the SOEC alternative, however with somewhat different parameter i.e. steam costs and no waste heat sales.

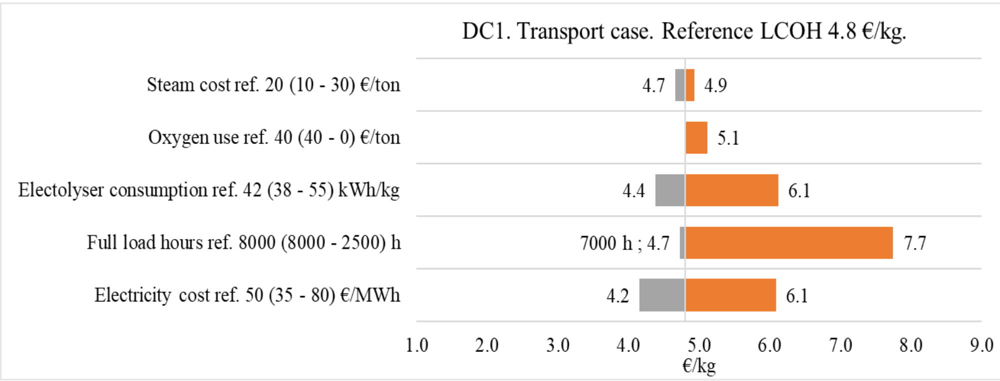


Figure 61. One variable sensitivity analysis of LCOH for SOEC DC1 scenario.

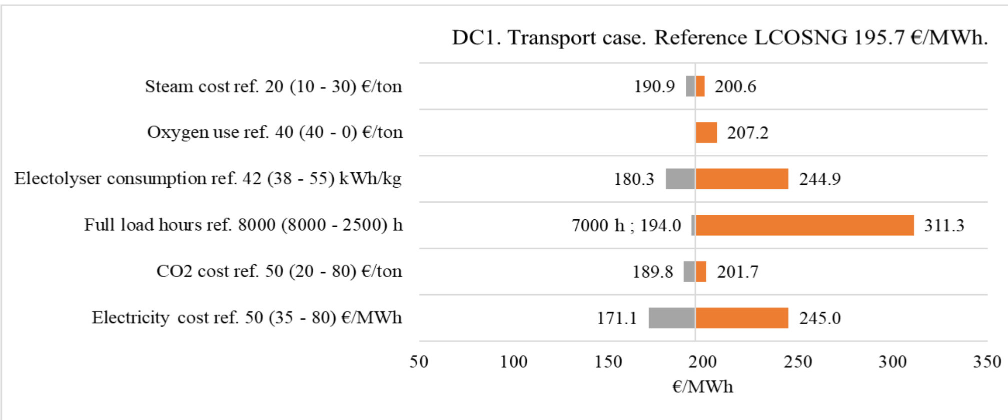


Figure 62. One variable sensitivity analysis of LCOSNG for SOEC DC1 scenario.

The side stream use for each case demonstrates their effect on the LCOH as the cost of hydrogen is affecting the SNG costs. However, the electricity costs, electrolysis system consumption (i.e. efficiency) and full load hours have the largest impact on the levelized costs. A notable difference in the SOEC alternative was that by reducing the full load hours to 7000 h, the levelized costs were slightly lower. Stack replacement frequency is longer with lower FLH in the SOEC case which decreases the cost impact of the replacement.

The lowest LCOH and LCOSNG from the sensitivity analyses resulted from the DC4 scenario, where LCOH was approx. 2 €/kg and LCOSNG approx. 90 €/MWh for the AEL case. Similarly for SOEC case, the LCOH was approx. 2.8 €/kg and LCOSNG was approx. 118 €/MWh. The lowest costs resulted from 35 €/MWh electricity costs.

The sensitivity analyses for all scenarios are presented in Appendix 4 for AEL and Appendix 5 for SOEC.

7.2 Discussion

This section discusses the results as presented previous section. First the feasibility study is evaluated and then the research questions and hypothesis are checked against the results. The current situation in Europe and its effect on the field of PtX is commented as well.

7.2.1 Feasibility study

The results from levelized costs and the NPV calculations indicate that the optimum setup for the PtX application in Vaasa region would be as follows.

For AEL alternative:

- Minimum production amount of SNG should be at least 6000 t/a with a sales price of at least 10 €/MWh above the LCOSNG.
- Running hours at full load preferably 8000 h.
- Electrolyser system efficiency (LHV) of at least 59.5 %.
- Full utilisation of oxygen and heat side stream sales.
- Renewable PPA for possible RFNBO certification.

For SOEC alternative:

- Minimum production amount of SNG should be at least 23.7 kt/a with a sales price of at least 2.5 €/MWh above the LCOSNG.
- Running hours at full load preferably 7000 h.
- Electrolyser system efficiency (LHV) of at least 79.3 %.
- Full utilisation of oxygen stream sales and coupled with a CHP plant.
- Renewable PPA for possible RFNBO certification.

The above suggestions are for the cases in this work that have an acceptable payback time. Scaling effect is recognisable in the economic assessments. For maximum financial gains the AEL case with above 23 kt/a SNG production would be the optimum, however it largely depends on the market price of natural gas and biogas. SOEC wasn´t a competitive alternative due its higher capital costs and the frequency of stack changes due the stack lifetime. SOEC capital costs should be in the range of approx. 1100 €/kW to start with to benefit from its higher efficiency. In addition, stack lifetimes must improve. The most probable alternative for Vaasa region would be a PtX system based on AEL technology.

CO_2 should be of biological origin from e.g. waste incineration biogenic CO_2 share or another biofueled CHP plant. This would constitute as a bioenergy carbon capture and utilisation (BECCU) project and would not contribute to the fossil fuel extraction process. It would provide the means to produce sustainable fuels with local efforts.

The positive NPV results came with the natural gas pump price that has recently been on the rise. The SNG sales prices could not compete with biogas prices nor the European reference price of natural gas in the scenarios. However, in case that a very low electricity price of 35 €/MWh, the SNG price could compete. Electrolyser efficiency was reflected in the sensitivity analyses, so an improvement of AEL efficiency to approx. 83 % (LHV) would result in a positive NPV with all price references from a SNG demand of above 11.8 kt/a.

As the techno-economic evaluation was based on demand, the reduction of full load hours is increasing the levelized costs. The plant sizing is based on the constant demand scenarios so reducing the running hours would result in significantly oversized electrolysers.

The research problem received a response in this work based on the demand scenarios uncovered from the interview results, however, a large gas demand is required to have a positive business case or extremely low electricity prices which might not be realistic. Electrolyser efficiency improvements on the other hand might be achievable in the near future. However, it must be noted that the SNG costs did not include storage, liquefaction nor transportation so these will have an increasing effect on the costs. Transporting hydrogen was also not considered. If hydrogen should be transported, Yang and Ogden (2007, 10) determined that the lowest cost of hydrogen transport mode was by truck at approx. 0.9 $/kg and via pipeline approx. 1.2 $/kg for hydrogen flow of 15 t/day and a radius of 50 km. However, the delivery method of hydrogen and SNG for a specific region would be a topic for another work.

The hypothesis of side stream use and electricity price impact on the feasibility and levelized costs was confirmed. To reiterate, the levelized costs define the minimum sales price for break even and therefore lowering the levelized costs is of importance. In addition to the hypothesis, the full load hours affect the economic results quite much.

7.2.2 Research questions

The research questions were the following:

- Where and who are the main key stakeholders and off-takers?
- What main products and side streams are utilised by who and how?
- Which technologies are favoured for main products and side streams and their geographical locations?
- Which regulations and value drivers are impacting the PtX ecosystem?

It can be said that there could exist a potential PtX ecosystem in Vaasa region based on the concentration of energy companies and their interest in PtX applications. The off-takers were identified, however, the PtX products should concentrate on the hard to electrify sectors such as maritime and heavy transport as the electrification of the light duty transport sector is accelerated alongside PtX development. In addition, there is uncertainty regarding off-taker realisation and integration to the field of PtX.

The main product that could be utilised was SNG via catalytic methanation as there were no large-scale hydrogen off-takers in Vaasa. AEL would be the best choice for electrolysis according to the feasibility results. The side stream use for oxygen would be only the battery manufacturing industry and if not materialised, revenue from oxygen sales might not get realised. The locations were identified in Figure 47 and they would be the most probable locations for industrial PtX sites and off-takers. Waste heat could be fed into the district heating network, provided that the local heating network provider is also involved in the project.

Value drivers for the ecosystem member constituted mostly on economic decision-based values which is feasibility of the business case. New and promising technology potential was also valued with the energy storage potential of PtX. Decarbonisation of own operations and national targets were also driving value points.

The regulation aspects were researched; however they are widely incomplete in terms of PtX and hydrogen. In Vaasa, the FuelEU Maritime regulation, ETS and ETD will have an impact on e.g. the local ferry operations and drive towards sustainable alternatives. RED will influence the PtX business decisions and way of certification. Furthermore, the discussed regulations will have an overall effect to the PtX application if they are completed on time. However, regulation is seen as necessary for transitioning to a renewables and hydrogen-based energy economy.

The following table summarises key timelines for different regulation aspects and targets.

Table 20. Summary of key regulation implementation timelines.

Year	2023	2024	2025	2030	2035
Updated ETD	(x) Jan				
Updated ETS	(x) December				
RED 2 amendment		(x) December			
ReFuel EU Aviation regulation			(x) Jan		
FuelEU Maritime regulation			(x) Jan		
Alternative fuels infrastructure regulation - hydrogen dispensers in urban nodes				(x) December	
EU hydrogen strategy - 40 GW electrolysers and 10 Mton of hydrogen				(x)	
National decarbonisation targets					(x)

The clarity need of upcoming regulations is of utmost importance so that the timeline for decarbonisation efforts can be kept and investment decisions can be made. In addition, national efforts on specific regulation preparation regarding hydrogen and RFNBOs should be accelerated.

7.2.3 Geopolitical situation

Europe is witnessing an attack on a sovereign nation which is still ongoing at the time of writing this thesis. The loss of life is irreparable, and the situation is very unfortunate for the people of Ukraine.

In addition to the destruction of life and infrastructure, the market situation in Europe has been affected due to the sanctions against Russia. Increased material as well as oil and gas prices are affecting prices globally. The Finnish government has decided to lease a floating LNG terminal to relieve the Finnish gas need from its reliance on Russian imports (Gasgrid Finland 2022d).

Furthermore, the EU has laid out a REPowerEU action plan in response to the current situation. The action plans target is to end the EU´s dependency on Russian fossil fuel imports. The short-term actions include, among others, accelerated roll out plans of solar and wind projects which are in combination of renewable hydrogen production. The medium-term measures which are aimed to be completed before 2027 includes a hydrogen accelerator which is aimed to build 17.5 GW of electrolyser capacity and 10 Mton of hydrogen production. A modern regulatory framework for hydrogen is also due by 2027 in the REPowerEU actions. (EC 2022b)

As it can be seen, the regulation aspects will likely change quite drastically in the coming years. And despite the market instability, the situation gives promise on PtX technology for ending the reliance on fossil fuel imports. It should also be of national interest to pursue technology options to increase domestic production of e.g. renewable hydrogen and synthetic fuels.

Since market situation is volatile and there is a lack of actual cost data, the results from this thesis can be determined on having a ± 30 % accuracy regarding the feasibility.

7.3 Future work suggestions

As this work could not cover all alternatives, future research topics based on identified knowledge gaps are suggested below.

- Life cycle assessment of GHG emission reduction of different PtX pathways compared with fossil fuel alternatives. Methodology definition and calculation of emission reductions.
- Regression analysis of existing natural gas pipeline construction costs in Finland for hydrogen pipeline infrastructure development and cost estimation.
- Heat management simulations for electrolyser and PtX process waste heat utilisation at different operating conditions in a local district heating network.
- Implications of completed EU regulations and national regulations regarding hydrogen and RFNBOs.
- Comparison of delivery alternatives via road and pipeline for hydrogen and SNG.

The above suggestions are based on the authors opinion on the knowledge gaps and represent the topics that could be of interest in PtX application.

8 Conclusions

The main objective was to find out regulatory and economic aspects which impact the application of PtX processes on a regional level. Furthermore, the technologies regarding the PtX processes, their outputs and side streams were studied to explore the alternatives that would best fit a feasible case study.

Hydrogen is currently produced mainly by means of fossil fuels and namely with fossil natural gas via SMR. The increasing amounts of renewable electricity that is projected to emerge will require energy storage mechanisms to manage the fluctuating output and maximise their potential. Green hydrogen production from e.g. wind energy and water electrolysis could facilitate the increased integration of renewable energy to a national energy scheme.

Electrolyser technologies are currently on the verge of large-scale development and considering the ambitious targets on the EU level to have 40 GW of electrolyser capacity by 2030 and the REPowerEU accelerated plans of 17.5 GW by 2027, the pace of development is expected to ramp up. AEL electrolysers are the mature choice and lowest cost alternative followed by PEM and SOEC. SOEC offers the potential to reduce electricity consumption with higher efficiency due to high temperature electrolysis, however it should be coupled with a steam source such as a CHP plant and its capital costs and stack lifetime needs improvement. Oxygen side stream and waste heat generated from low temperature electrolysers offer overall costs reductions for hydrogen production if they are utilised to the fullest. Transporting and storing hydrogen is a dilemma as it is the lightest element of the universe that requires significant efforts in terms of infrastructure and storage alternatives development.

Carbon capture can reduce the CO_2 impact from a point source; however the energy consumption of the process should improve. The associated hazardous waste side stream, especially with MEA based carbon capture, must be handled suitably. Nevertheless, when capturing CO_2 from a point source and the CO_2 being of biogenic source, it can be used to produce synthetic fuels via e.g. methanation which can be used already in today's machinery and infrastructure. CCU and hydrogen can be used to produce fuels that are traditionally extracted from finite resources.

Regulation wise, the Fit For 55 package provides numerous legislative proposals to assist in decarbonising several sectors and increasing renewable energy deployment to achieve GHG emission savings. The amendment of RED 2 will provide guidelines towards RFNBO production, however the methodologies and rule definitions should be concluded as soon as possible so that Member States have the suitable means to proceed implementing national level guidelines and regulations for RFNBO production to provide confidence in investment decisions. The RFNBO certification system should also be harmonised EU wide so that producers and off-takers have the means to prove the origin for sustainable hydrogen and its derivatives. Regulation should be straightforward and not too restrictive for PtX.

Additional and extended regulations such as ETD, ETS, FuelEU Maritime, ReFuelEU Aviation as well as Alternative fuels infrastructure regulation can facilitate the uptake of sustainable fuels such as hydrogen and synthetic fuels. However, increased regulation will also affect the cost of fuels in short-term and commodity prices since fuel producers and sectors such as maritime and aviation are affected.

The techno-economic assessment for the regional case study showed that at a suitable price level, the PtM application in Vaasa region could be feasible provided that the production amount is above 6000 kt/a of methane with suitable off-takers for main product and side streams. Further development of electrolysis technology i.e. efficiency improvement and low electricity costs could make PtM competitive against even the reference price of natural gas. Furthermore, there could emerge a potential PtX ecosystem in Vaasa based on the current capabilities.

The transitioning phase from fossil-fuel based economy to a more sustainable and renewables based will cause extra costs, however the initial costs must be carried so that economies of scale can start to influence the sustainable alternatives. The costs of not doing so are much larger.

To conclude, the research provided satisfactory answers to the research problem and questions. However, in the authors opinion, more accuracy could have been achieved by specific simulations on the processes and having real costs for the equipment in question. Nevertheless, an overall holistic picture of the field of PtX and the regulatory environment was achieved. The author has a strong confidence that PtX and hydrogen applications will play an important role in the coming years.

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Appendix 1. Interview form.

Theme 1: Market potential in Vaasa region
What kind of potential do you see in P2X products (green hydrogen, synthetic fuels, other products) and side streams (oxygen, heat)? How about grid service i.e. X2P? Considering a timeline of present situation until 2030.

How do you see the priority of synthetic fuels from P2X process for application in Vaasa region?

- Please rate e-fuels; Methane, Methanol, Gasoline, Diesel, Ammonia in order of 1 – 5; 1 being the highest and 5 being the lowest priority for synthesis products

Priority 1	Priority 2	Priority 3	Priority 4	Priority 5

- Any other relevant products to be considered?

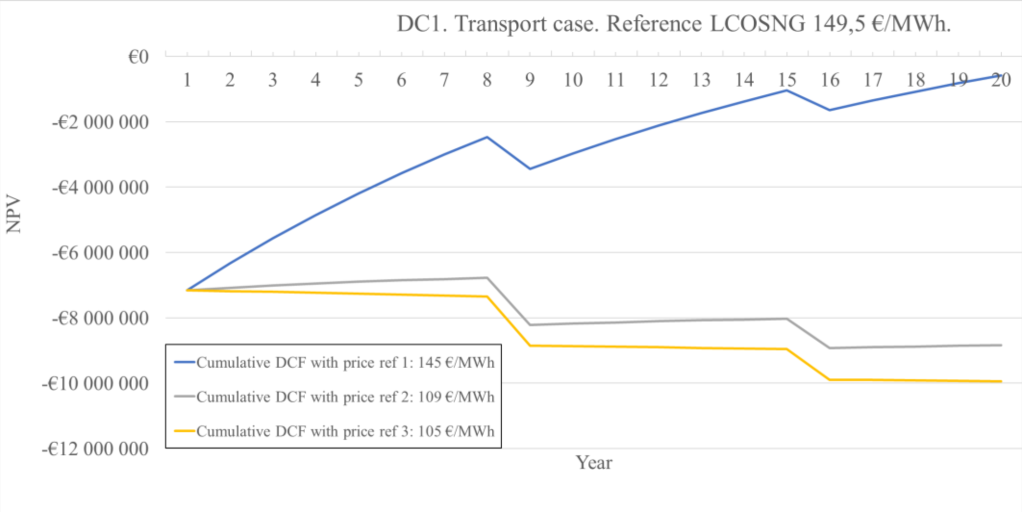
What kind of infrastructure development is missing or is in place for sector integration (i.e. electricity, district heating, transport sector coupling)?

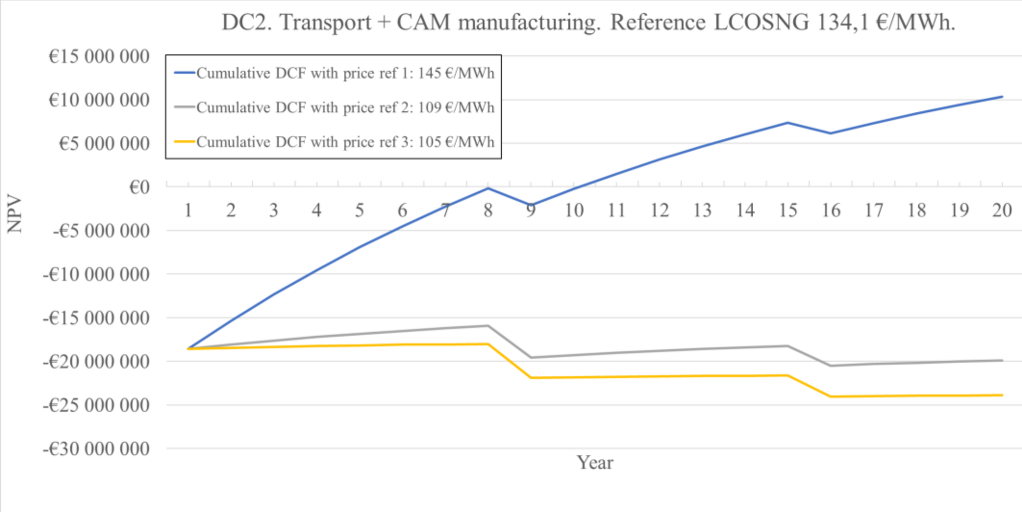
Theme 2: Value drivers for a business case
What do you see that would be your company's value drivers in a P2X ecosystem / business case?

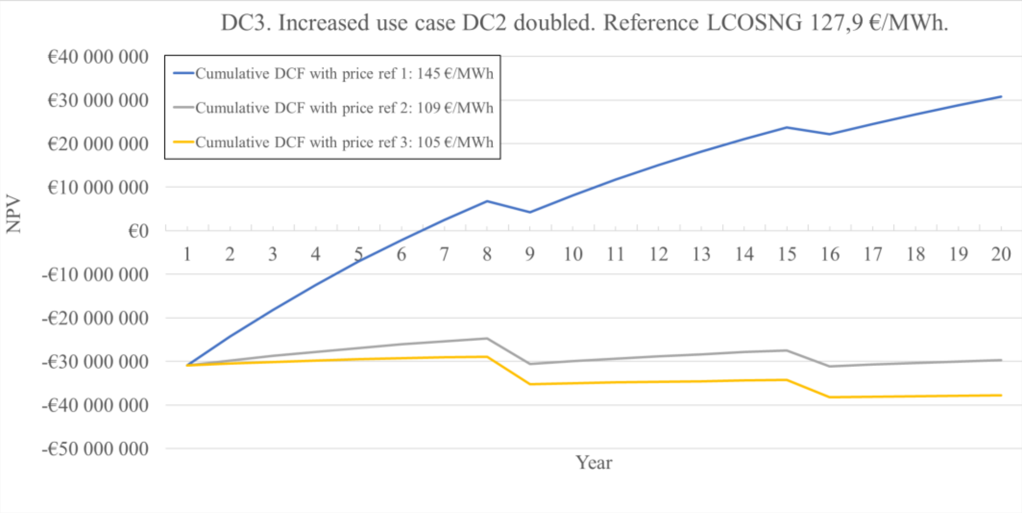
Theme 3: Role
How do you see your company´s role in a P2X ecosystem?

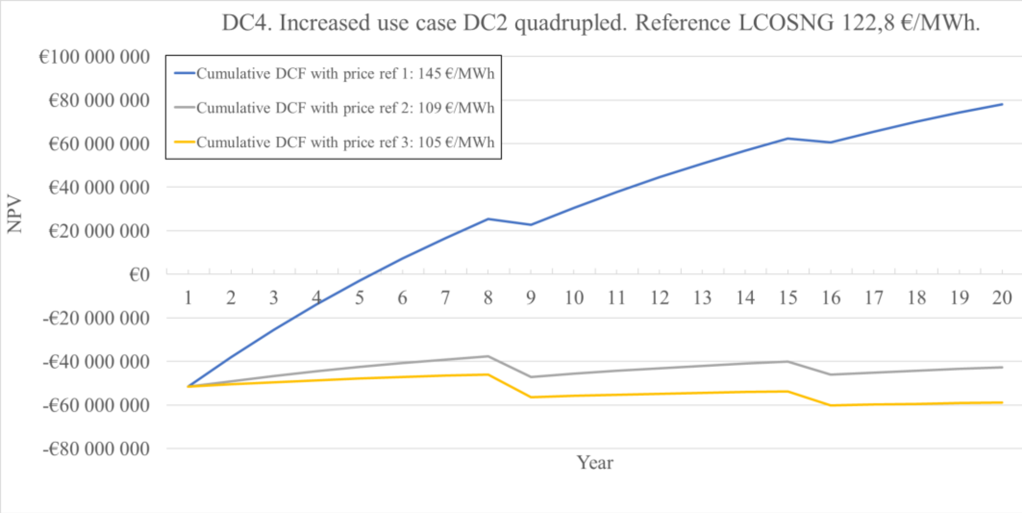
Theme 4: Regulation
What kind of regulation drivers effect your company´s role in a P2X ecosystem?

Appendix 2. Cumulative discounted cashflows for AEL alternative in different demand scenarios.

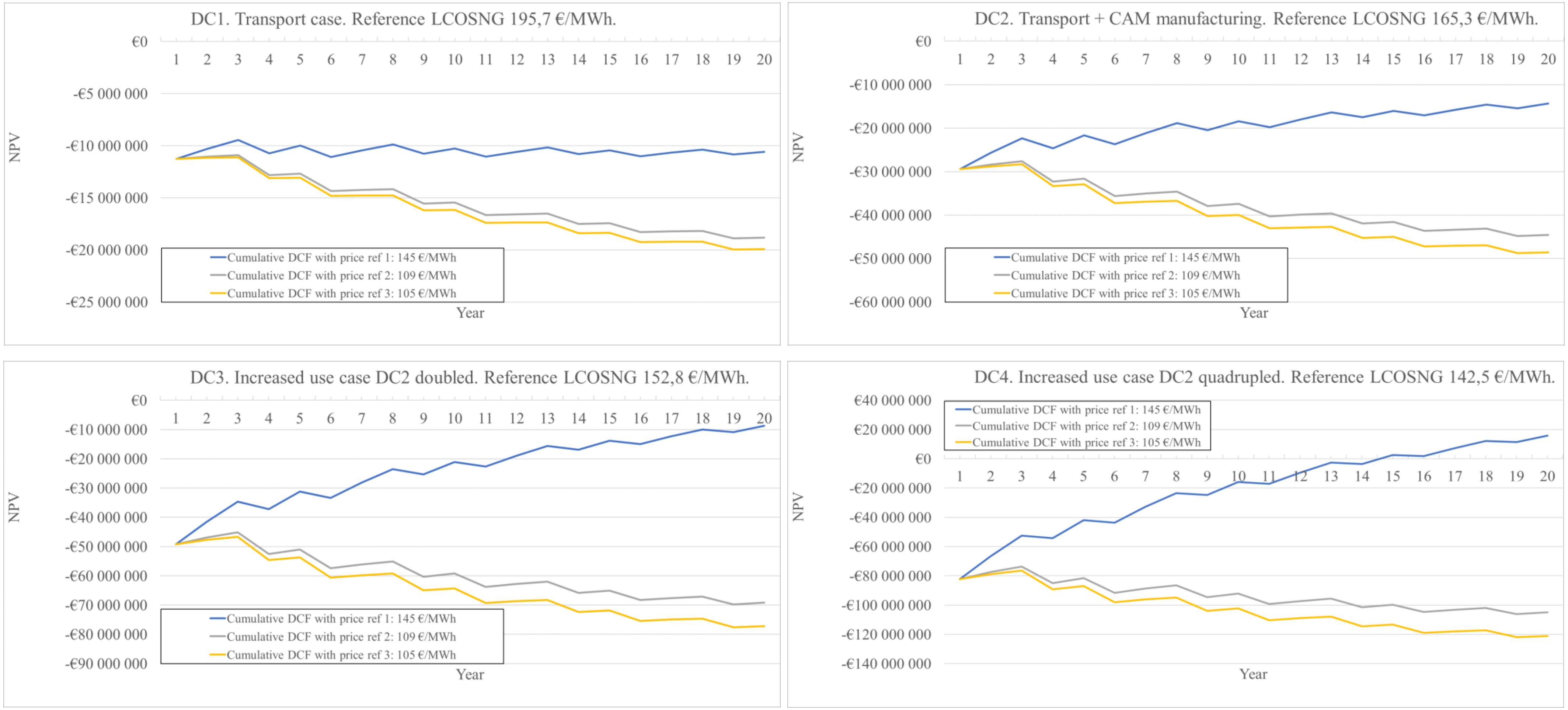






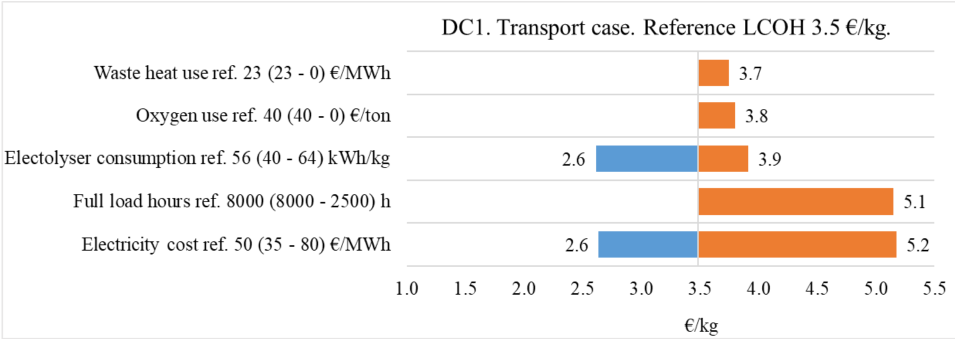


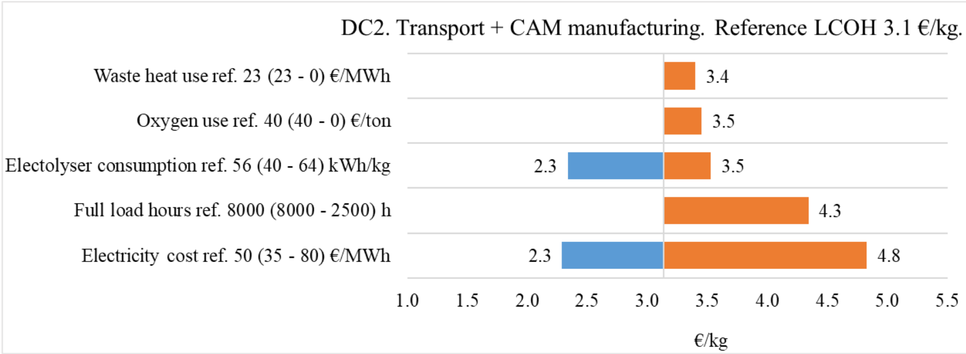
Appendix 3. Cumulative discounted cashflows for SOEC alternative in different demand scenarios.

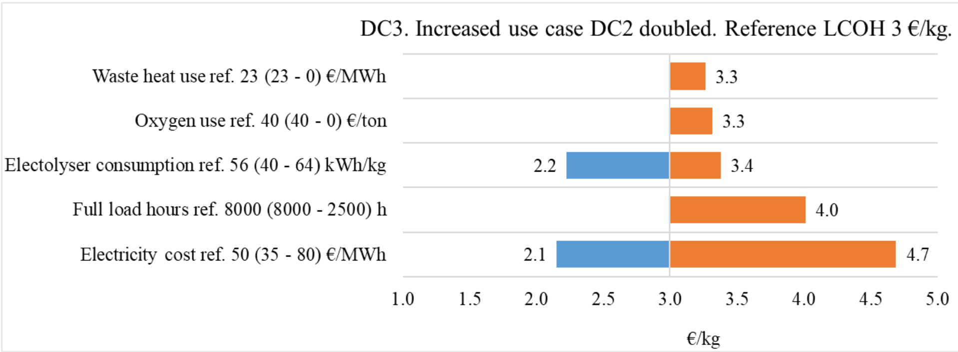


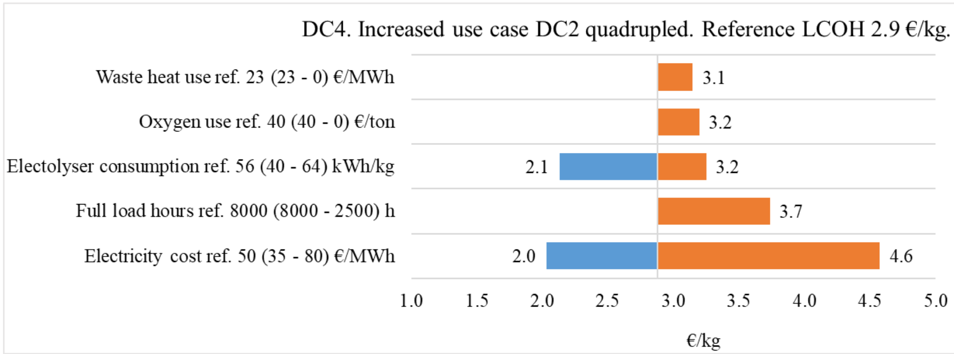
Appendix 4. LCOH and LCOSNG sensitivity analysis for AEL alternative in different demand scenarios.

One variable sensitivity LCOH

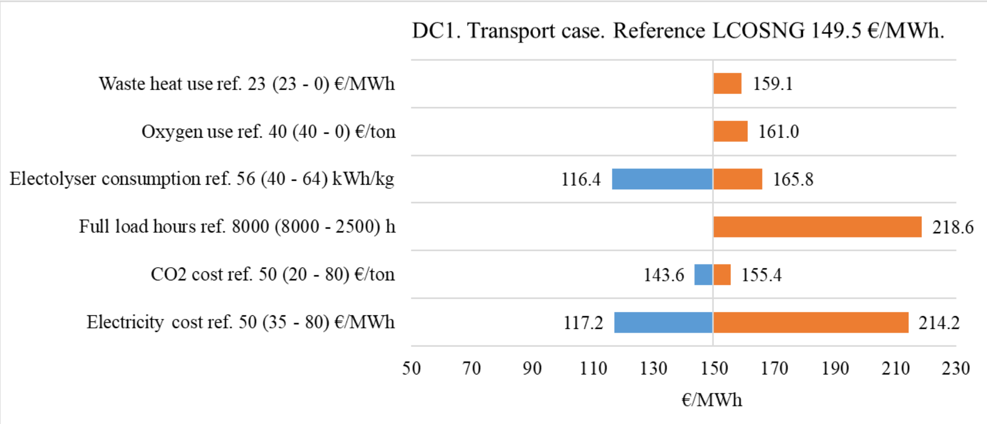


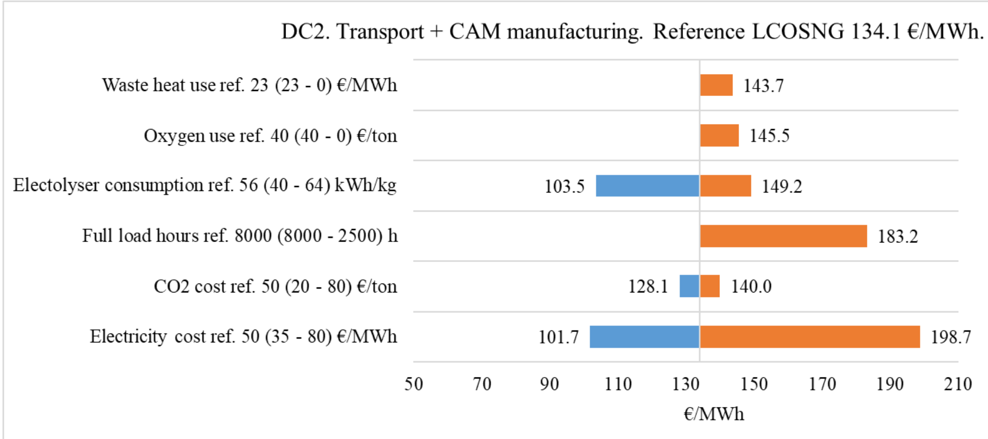


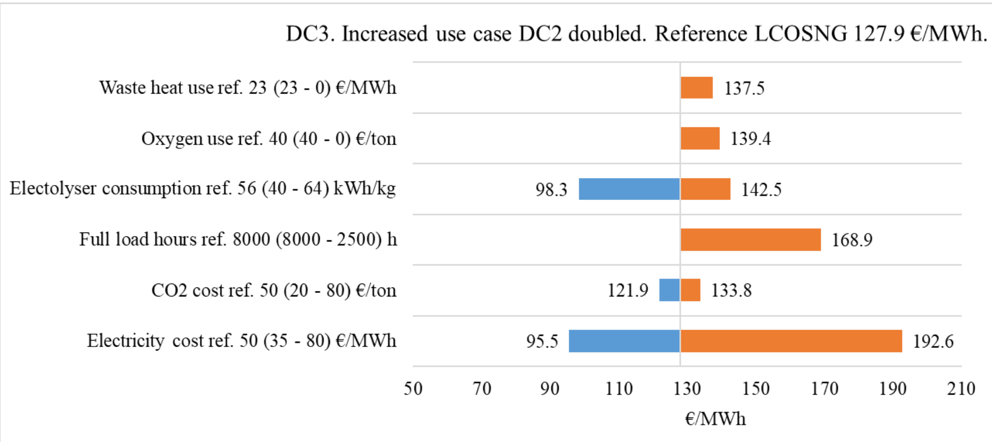


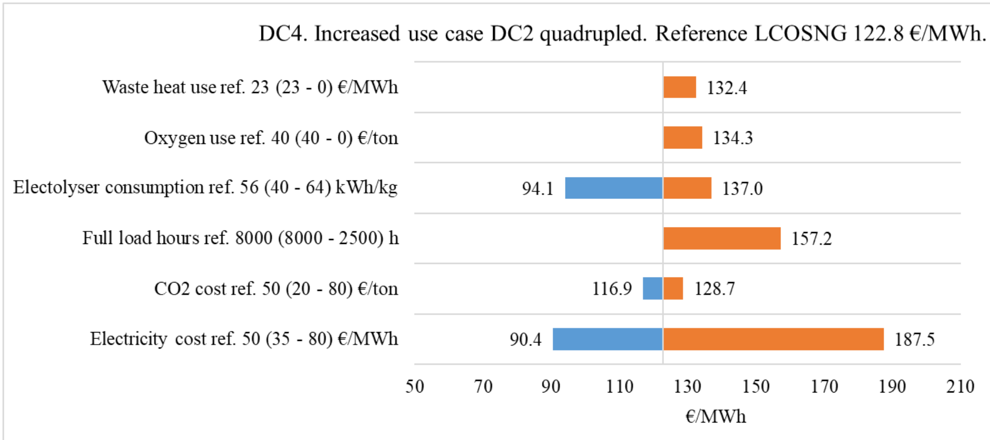


One variable sensitivity LCOSNG



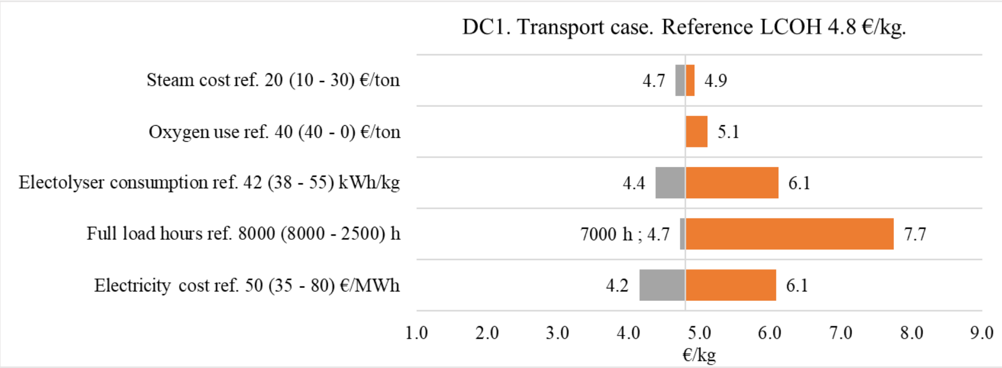


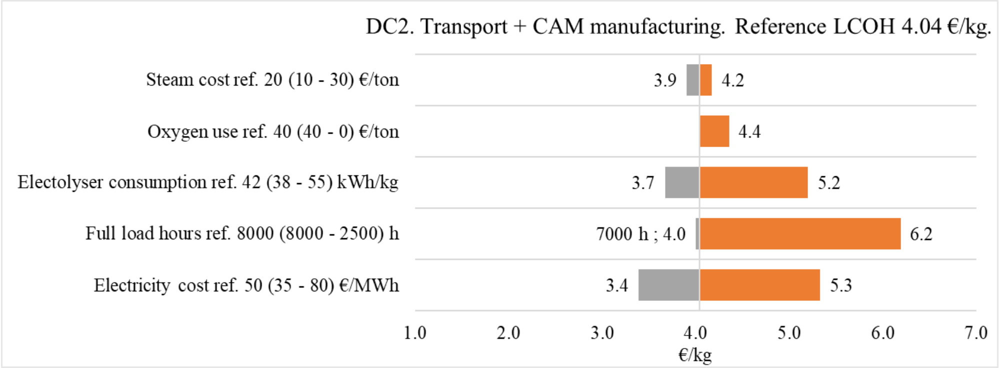


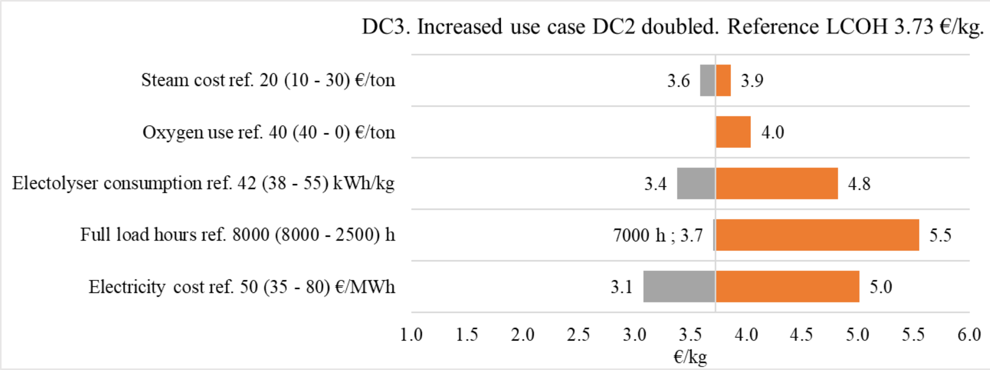


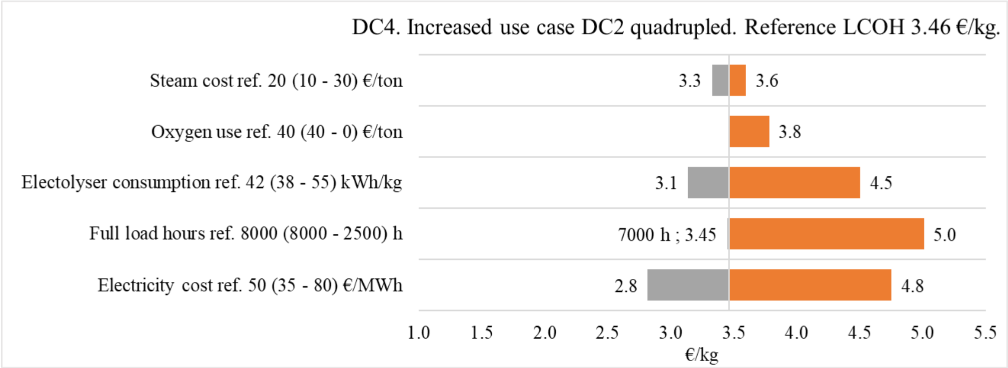
Appendix 5. LCOH and LCOSNG sensitivity analysis for SOEC alternative in different demand scenarios.

One variable sensitivity LCOH









One variable sensitivity LCOSNG