Tampereen yliopisto

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FOSSIL-FREE COATING DRYING
Replacing natural gas in process heat production

Master's Thesis
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ABSTRACT

Neela Walin: Fossil-free coating drying: Replacing natural gas in process heat production
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Natural gas is used in industrial processes for process heat production, amongst other things. Despite natural gas having lower emissions than other fossil fuels, its combustion contributes to climate change and the problems arising from global warming. In the European Union (EU), approximately 30 % of used natural gas is consumed in the industry sector. Decarbonizing industry presents a big emission reduction potential, but industry is a heterogeneous sector, and different industries will require different solutions.

Multiple options for decarbonization are possible, but based on a literature study electrification, alternative fuels, solar thermal technologies, and carbon capture and storage (CCS) were further explored in this thesis. All these technologies have their own advantages and disadvantages that were evaluated against the criteria of a pressure sensitive label manufacturing process.

Pressure sensitive label is manufactured in a process where different layers are stacked on top of a release liner. These layers need to be dried in drying ovens that are currently heated up to 200 °C with gas burners that mainly utilize natural gas. Once the drying process is complete the release liner is laminated together with a face material to produce a complete product.

The decarbonization of two coating machines in Country 1 (C1) and Country 2 (C2) was examined in this study. The technologies discovered in the literature study were ranked by nine criteria specific to this manufacturing process. The top two highest ranked decarbonization solutions (electrification with an electric boiler and biomethane) for both C1 and C2 were then evaluated more thoroughly in an economic and environmental study. Using the net present value (NPV) method investment calculations were done for both case studies. The NPV in both cases went into the negatives and there was no payback time for the electrification investment with a 7 % interest rate. To have a payback time of three years electricity price had to be 7.55 €/MWh in C1 and 10.08 €/MWh in C2. This is a very low electricity price considering the countries' usual price level.

The environmental benefits of electrification or using biomethane are significant. Switching fuels to biomethane or electrifying the drying process with electricity from renewable sources can lead to 100 % emission reductions. However, using electricity from renewable sources for electrification is essential as emissions can increase if the emission factor for electricity generation is very high.

In the cases where emissions were reduced a levelized cost for carbon abatement (LCCA) was calculated. In C1 the lowest value for LCCA was achieved in the case of electrification with electricity from renewable sources. The LCCA was 118.06 €/tCO_2e. Similar results were obtained for C2 where LCCA for electrification through renewables was 221.11 €/tCO_2e. Even the lowest values for LCCA were quite high considering the price for carbon in emissions trading has stayed under or close to 100 €/tCO_2e. Switching to biomethane resulted in an LCCA of 197.12 €/MWh and 245.29 €/MWh for C1 and C2, respectively.

This study shows that there is a plethora of options that can be considered when decarbonizing an industrial process, but options need to be individually evaluated for different processes. The results of this thesis suggest that decarbonizing can be economically non-feasible while environmentally beneficial. Technological development and development in energy prices will have a significant impact on the economic feasibility of decarbonization and therefore the rate of deployment these solutions will have.

Keywords: natural gas, process heat, fossil-free industry, pressure sensitive label, LCCA

TIIVISTELMÄ

Neela Walin: Fossiilivapaa pinnoitteen kuivatus: Maakaasun korvaaminen prosessilämmön tuotannossa
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Maakaasua käytetään teollisissa prosesseissa muun muassa prosessilämmön tuottamiseen. Vaikka maakaasun päästöt ovat muita fossiilisia polttoaineita pienemmät, sen polttaminen edistää ilmastonmuutosta ja ilmaston lämpenemisestä aiheutuvia ongelmia. EU:ssa noin 30 % käytetystä maakaasusta kulutetaan teollisuudessa. Fossiilittomien teknologioiden integroiminen teollisuuden prosesseihin luo mahdollisuuden suuriin päästövähennyksiin, mutta teollisuus on toimialana monipuolinen, ja tarvitsee erilaisia ratkaisuja hiilidioksidipäästöjen vähentämiseen.

Teollisen prosessin päästöjen vähentämiseen on olemassa monia ratkaisuja. Kirjallisuustutkimuksen perusteella tässä opinnäytetyössä tutkittiin tarkemmin sähköistämistä, vaihtoehtoisia polttoaineita, aurinkolämpöteknologioita sekä hiilidioksidin talteenottoa ja varastointia. Kaikilla näillä teknologioilla on omat hyvät ja huonot puolensa, joita arvioitiin tarralaminaatin tuotannon näkökulmasta.

Tarralaminaatti valmistetaan prosessissa, jossa eri kerroksia kerrostetaan taustamateriaalin päälle. Eri kerrokset on kuivattava kuivatusuuneissa, joita tällä hetkellä lämmitetään 200 asteeseen asti pääasiassa maakaasua käyttävillä kaasupolttimilla. Kun kuivausprosessi on valmis, taustapaperi laminoidaan yhteen pintamateriaalin kanssa lopullisen tuotteen valmistamiseksi.

Työssä arvioitiin kahden, maassa 1 (C1) ja 2 (C2) sijaitsevan, päällystyskoneen hiilidioksidipäästöjen vähentämistä. Kirjallisuustutkimuksessa esiin nousseet teknologiat asetettiin paremmuusjärjestykseen kyseiseen tuotantoprosessiin liittyvien kriteereiden perusteella. Kaksi parasta ratkaisua hiilidioksidipäästöjen vähentämiseksi (sähköistys sähkökattilalla ja biometaani) arvioitiin perusteellisemmin omassa talous- ja ympäristötutkimuksessa. Molemmille tapaustutkimuksille tehtiin investointilaskelmat nettonykyarvomenetelmällä (NPV). Molempien tapausten nettonykyarvo oli negatiivinen, eikä sähköistysinvestoinnille saatu takaisinmaksuaikaa 7 %:n korolla. Kolmen vuoden takaisinmaksuajan saamiseksi sähkön hinnan tuli olla C1:ssä 7,55 €/MWh ja C2:ssa 10,08 €/MWh. Tämä on maiden tavanomaiseen hintatasoon nähden erittäin alhainen hinta.

Sähköistyksen tai biometaanin käytön ympäristöhyödyt ovat merkittäviä. Vaihtamalla biometaaniin tai sähköistämällä vihreällä sähköllä kuivausprosessin päästöjä voidaan vähentää 100 %. Päästövähennysten kannalta on kuitenkin oleellista, että vihreän sähkön käyttäminen on mahdollista, sillä päästöt voivat kasvaa, mikäli käytetyn sähkön päästökerroin on suuri.

Tilanteille, joissa päästöt vähenivät, laskettiin hiilidioksidipäästöjen vähentämiskustannukset (LCCA). C1:ssä alhaisin LCCA-arvo sähköistykselle saavutettiin käyttämällä vihreää sähköä. LCCA oli 118,06 €/tCO2e. Samankaltaisia tuloksia saatiin C2:sta, jossa vihreää sähköä käyttämällä LCCA oli 221,11 €/tCO2e. LCCA:n alimmatkin arvot olivat melko korkeita ottaen huomioon, että hiilidioksidin hinta päästökaupassa on viime vuosina pysynyt selvästi alle tai lähellä 100 €/tCO2e. Biometaaniin vaihtamalla LCCA:n arvoksi saatiin 197.12 €/MWh ja 245.29 €/MWh maille 1 ja 2.

Tämä tutkimus osoittaa, että teollisen prosessin hiilidioksidipäästöjen vähentämisessä voidaan harkita monia vaihtoehtoja, mutta vaihtoehtoja on aina harkittava yksitellen eri prosesseille. Tämän opinnäytetyön tulokset viittaavat siihen, että hiilidioksidipäästöjen vähentäminen voi olla taloudellisesti kannattamatonta, vaikka se olisi ilmaston kannalta hyödyllistä. Teknologisella kehityksellä ja energian hintojen kehityksellä on merkittävä vaikutus hiilidioksidipäästöjen vähentämisen taloudelliseen kannattavuuteen ja siten näiden ratkaisujen käyttöönottoasteeseen.

Avainsanat: maakaasu, prosessilämpö, fossiilivapaa teollisuus, tarralaminaatti, LCCA

PREFACE

This study was enabled by UPM Raflatac, a Finnish, globally operating company that specializes in the manufacturing of label products. The subject matter of this thesis is very topical and interesting, and I want to thank the company for providing me with an opportunity to deepen my knowledge of this subject. A special thank you to Ilkka Naatti from UPM Raflatac for constant support and direction throughout this process. Also, a big thank you to Jukka Konttinen from Tampere University for the insight and help regarding this thesis.

I would also like to thank my parents for giving me an excellent starting point for my academic career and then continuing to give me advice throughout the hard parts. Thank you YKI for giving me a community and a safe place to grow as a young adult and thank you HupaKlubben – especially Emma and Venla – for your invaluable friendship throughout my years at Tampere University. Finally, thank you Antti for supporting me for all these years. Your companionship means the world to me.

This thesis concludes my studies at Tampere University. The past seven years have been an unforgettable experience – a roller coaster, one might say – and I leave this place with the friends, knowledge, and appreciation for engineering and technology, that I have gained along the way.

In Tampere, 20.8.2024

Neela Walin

CONTENTS

ABBREVIATIONS AND SYMBOLS

AD	Anaerobic Digestion
AEM	Anion Exchange Membrane
CCS	Carbon Capture and Storage
CH_4	Methane
CM	Coating Machine
COP	Coefficient of Performance
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
ETC	Evacuated Tube Collector
EU	European Union
FPC	Flat Plate Collector
GHG	Greenhouse Gas
GWP	Global Warming Potential
H_2	Hydrogen
HENG	Hydrogen Enriched Natural Gas
HTHP	High-temperature Heat Pump
HTF	Heat Transfer Fluid
IPCC	Intergovernmental Panel on Climate Change
IRR	Internal Rate of Return
LCCA	Levelized Cost of Carbon Abatement
LFR	Linear Fresnel Reflector
NG	Natural Gas
NPV	Net Present Value
ODP	Ozone Depletion Potential
PCM	Phase-change Material
PEM	Polymer Electrolyte Membrane
PTC	Parabolic Trough Collector
PVF	Present Value Factor
ROI	Return On Investment
SOE	Solid Oxide Electrolyser
TRL	Technology Readiness Level
UV	Ultraviolet

C	change in cashflow after an investment
E_0	emissions from an old system
E_1	emissions from a new system
i	investment hurdle rate
I_0	investment cost
I_n	depreciation value of investment
n	investment lifetime
NCF_t	investment annual net cash flow
r	discount rate
t	time

1. INTRODUCTION

The Intergovernmental Panel for Climate Change (IPCC) states that the global surface temperature has already risen by 1.1°C from 1850-1900 due to human activities (IPCC, 2023). This human-caused warming is mostly the result of using fossil fuels in energy production, transportation, and other industrial processes. If greenhouse gas (GHG) emissions are not considerably reduced, the warming will continue causing more extreme weather phenomena, such as extreme drought, floods, and severe storms. Committing to international targets, like the Paris agreement, means reducing the use of fossil fuels in every sector including the industry.

In industry, process heat is used in the making of manufactured goods. Process heat represents a large portion of industrial energy demand as almost 75 % of it comes from process heat (IEA, 2017). Fossil fuel combustion is still the most common way of producing process heat. Because of this, process heat production is the main source of direct industrial CO_2 emissions (IEA, 2018), which were approximately 9 Gt CO_2 in 2022 (IEA, 2023a). However, the nature of process heat usage makes industry quite hard to decarbonize. One solution is not necessarily applicable to all processes, since the range of industrial processes is extensive and heterogeneous. Yet, as previously mentioned, industry is responsible for a large share of global CO_2 emissions and thus the emission reduction potential is significant.

Climate issues are not the only incentive to decarbonize process heat. In 2021 22.6 % of natural gas (NG) consumed in the European Union (EU) was used in industrial processes (excluding power and heating generation). During the same year, on average 45 % of natural gas used in the EU came from Russia alone. (European Council, 2023) The Russian invasion in Ukraine changed the European energy markets drastically. The sanctions on Russia forced the diversification away from Russian natural gas, and the war also increased energy prices making natural gas less cost-effective and thus, a less attractive option than it had been before. The war in Ukraine is on-going and the use of Russian natural gas in the EU is currently unlikely to return to same levels as it was before the war. (European Council, 2024) Together the changes in the energy market and the pressure of climate change mitigation give a strong incentive to pursue a fossil-free future.

In this thesis different ways of replacing natural gas in low-/medium-temperature process heat production are examined. The study is done from the point of view of UPM Raflatac, a Finnish, internationally operating company that uses natural gas in its pressure sensitive label manufacturing process for heat production. Different methods of replacing natural gas are mapped out with a literature study to give the company a comprehensive review of the options that are currently available for decarbonization or will be before 2030. The technologies that are discovered in the literature study are then ranked with the pressure sensitive label manufacturing process in mind, and a more in-depth economic and environmental study is done to the two most potential technologies for both case studies in country 1 (C1) and country 2 (C2). Finally, the results and the possibility to implement them in this industry are assessed. The research questions that are studied in this thesis are:

1. How is fossil-free heat produced in industrial processes?
2. What fossil-free source of energy could replace the natural gas used in the pressure sensitive label manufacturing process by 2030?
3. What are the effects of replacing natural gas in process heat production?
4. What fossil-free technologies seem most potential for new coating machines built after 2030?

In the second chapter of this thesis the properties, availability, and problems of natural gas as a fuel are examined. Based on the literature study, the potential fossil-free alternatives for natural gas are also presented. The third chapter goes into the calculation methods of the economic and environmental study, while chapter four presents the pressure sensitive label making process and the premise for the economic and environmental studies. In chapter five the results of these studies are presented followed by chapter six where the results, their impact, and the needs for further research are discussed. The final chapter in this thesis summarizes what the goals of this research were, how the goals were pursued, what were the key results, and what can be concluded from those results.

2. NATURAL GAS PROPERTIES AND REPLACING IT IN PROCESS HEAT PRODUCTION

In this chapter an overview of natural gas is given, and properties of natural gas as a fuel in medium-temperature process heat production are examined. A review of the use and outlook of natural gas is also presented. The review focuses on the European gas market, since the case study factories of this thesis are in two European countries, C1 and C2. Based on a comprehensive literature study, an array of alternatives for natural gas in process heat production is then presented. Examples of how these alternatives have been integrated in different industries are given, followed by a summary of the presented solutions.

2.1 Natural gas as a source of process heat

Natural gas is an odorless, colorless, combustible fossil fuel that consists mainly of methane (CH_4). The methane content of natural gas varies depending on the place and type of reservoir the gas has been extracted from. Natural gas with a higher percentage of methane is more suitable for combustion than natural gas with more heavy hydrocarbons such as propane and butane (Finnish Gas Association, 2014). Some compositions of natural gas with a high methane content are listed in Table 1.

Table 1. *Different compositions of natural gas.*

Component	*Russian NG [1]*	*Dry NG [2]*	*Dry NG from California [3]*	*NG [4]*
Methane CH_4	98 %	96 %	95.8 %	92.93 %
Ethane C_2H_6	0.8 %	2.0 %	2.9 %	5.34 %
Propane C_3H_8	0.2 %	0.6 %	0.4 %	1.07 %
Butane C_4H_{10}	0.02 %	0.3 %	0.1 %	0.5 %
Nitrogen N_2	0.9 %		0.8 %	0.15 %
Carbon dioxide CO_2	0.1 %			

[1] Finnish Gas Association, 2014

[2] Faramawy et al. 2016

[3] Khilyuk et al. 2000

[4] Park et al. 2021

In terms of combusting fuels, one of the most important properties of a fuel is its heating value. It states the amount of energy that can be produced from a certain quantity of fuel. Natural gas has a relatively high heating value as its lower heating value is approximately 50.0 MJ/kg (Finnish Gas Association, 2014; Thiel & Stark, 2021). For comparison, the lower heating value for heavy fuel oil and coal are 41 MJ/kg and 28 MJ/kg, respectively (Alakangas, 2000). In terms of heating value, natural gas is an efficient fuel: the same amount of energy can be obtained by burning a smaller amount of fuel.

Chemically speaking, burning natural gas is a complicated process, but since natural gas consists mostly of methane, the chemical reaction of burning methane (Equation 1) can be used as an approximate to describe the burning reaction of natural gas.

$$CH_4 + 2\ O_2 \rightarrow CO_2 + 2\ H_2O \tag{1}$$

As can be seen from the reaction equation, burning natural gas produces CO_2 emissions. However, the carbon to hydrogen ratio of natural gas is lower than the ratio of many other fossil fuels. This results in lower CO_2 emissions compared to other fossil fuels. (Akhtar et al. 2016) The CO_2 emissions from natural gas are approximately 70 % of the emissions from heavy fuel oil and 55 % of the emissions from coal (EIA, 2023), which has led to natural gas being used as a transition fuel in reducing GHGs. Natural gas also burns relatively purely. It doesn’t produce significant amounts of ash, soot, or particulate matter, and since it doesn’t contain sulfur compounds, sulfur oxides (SO_x) are not emitted when burning it. (Motiva, 2023b) Despite the smaller emissions, natural gas is a fossil fuel and needs to eventually be phased out to adhere to international climate goals.

In addition to natural gas’ smaller emissions, one clear advantage of natural gas has been its relatively affordable and stable price. For the past 10 years the price in Europe has fluctuated between 15-20 €/MWh. This changed in 2021 when Russia started withholding gas imports to Europe. In August of 2022 the price went over 300 €/MWh. The price has since come down nearly to the pre-energy crisis levels of 2021, but the price volatility has made natural gas a less attractive investment than before. (Trading Economics, 2024)

Despite this, natural gas is still used for energy production in all the major sectors including industry, residential use, and electricity generation. (EASAC, 2023) Figure 1 illustrates the natural gas consumption of these sectors in the EU in 2020.

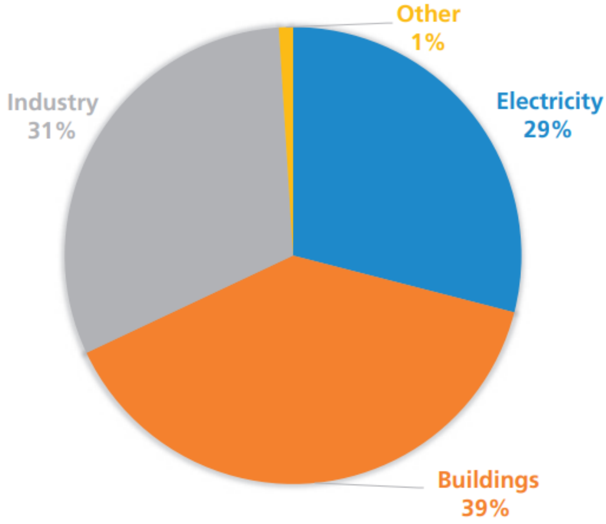

Figure 1. *Consumption of natural gas in different sectors in the EU in 2020. (EASAC, 2023)*

In the EU the largest portion of natural gas is used to heat buildings. This includes individual heating and district heating. Industry is the second largest sector for natural gas consumption. It includes for example process heat production and using natural gas as a raw material to produce different goods. Electricity production is also a large consumer of natural gas with a 29 % share in 2020. The remaining part includes, among others, use of natural gas in transport. (EASAC, 2023)

In 2022 natural gas consumption in the EU was approximately 13.7 thousand petajoules (PJ). The Russian invasion in Ukraine resulted in a 13.2 % decrease in consumption compared to 2021. (Eurostat, 2023) Natural gas consumption dropped the most in C1 where it was reduced by 48 %.

Currently only about 3 % of energy consumption in C1 is attributed to natural gas, consumption being 39 PJ in 2022. (Motiva, 2023a) In C1, pulp and paper industry, manufacturing of basic metals, chemicals industry, and food processing industries are the biggest industries using natural gas. Pulp and paper industry is by far the largest industrial consumer of natural gas with a consumption of 14 PJ in 2022. The production of basic metals is the second largest consumer with a 6 PJ consumption. (Statistics Finland, 2023)

The home country of the second case study factory of this thesis, C2, is one of the seven largest natural gas consumers in the EU. Together these countries consume almost 80 % of the natural gas used in the EU. (EASAC, 2023) In 2021, the natural gas consumption in C2 was over 650 PJ. Of this approximately 177 PJ was used in the industry sector presenting a significant emission reduction potential if industry was decarbonized. (IEA, 2022a)

2.2 Alternatives for natural gas

As stated, replacing natural gas in process heat production presents a significant potential to reduce industry's CO_2 emissions, but decarbonizing industry is hard due to its heterogeneity. One solution will not be suitable for all industrial processes.

Next, different technologies for replacing natural gas are analyzed based on literary research. The aim was to map out the most common and potential alternatives for natural gas by examining scientific publications, comprehensive reports, and discussion around the topic. The focus was especially on solutions for low- and medium-temperature (up to 400°C) process heat production, since high-temperature process heat is not used in the case study process.

2.2.1 Electrification

Electrification of process heat production is widely acknowledged as a way to reduce the use of fossil fuels and reduce the greenhouse gas (GHG) emissions of industry (EASAC, 2023; Thiel & Stark, 2021; Motiva, 2021). Electrification can happen directly, for example, by replacing gas burners with resistive heating, but it can also be indirect. For example, alternative fuels such as hydrogen can be produced by using electricity and then used to decarbonize an industrial process. (Motiva, 2021) In this chapter, direct ways of electrification are explored.

Replacing natural gas with electricity in process heat production can be done using a range of different technologies. Divided in to four different categories, the technologies are heat pumps, resistive heating, electromagnetic heating, and technologies that use electric arcs (Schüwer & Schneider, 2018; Schoeneberger *et al.*, 2020). Heat pumps are discussed later in the thesis in their own chapter, and electric arcs in industry are mostly used in high-temperature applications such as electric arc furnaces (Jegoroff *et al.*2021). Therefore, the technologies discussed more in depth in relation to electrifying an industrial, medium-temperature heating process, are resistive and electromagnetic heating.

Resistive heating or Joule heating is a simple heating method where electric current is passed through a resistor creating heat. Resistive heating can be separated to direct and indirect resistive heating. Direct resistive heating heats the target directly using its own resistance, whereas indirect resistive heating utilizes a heat transfer medium that is heated first. The heat transfer medium then heats the intended target either with convection or radiation. (Beyond Zero Emissions, 2018) The principle of direct resistive heating is illustrated in Figure 2.

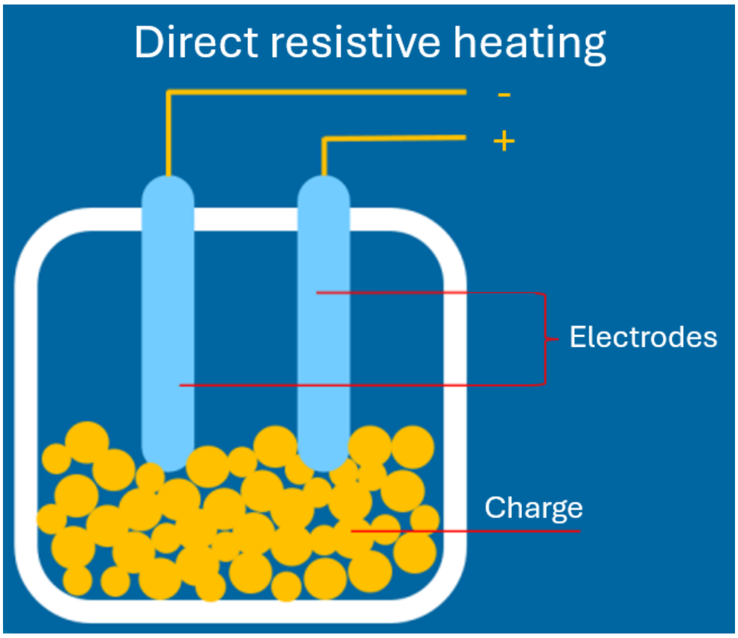

Figure 2. *Working principle of direct resistive heating. (Altered from Jegoroff et al. 2021)*

Resistive heating can supply heat up to 1800°C and is therefore applicable to processes needing low- to high-temperature heat making it quite versatile. Additionally, the thermal efficiency of resistive heating can be nearly 100 %. (Jegoroff *et al.* 2021)

Electromagnetic heating technologies use a range of electromagnetic radiation to produce heat. There are five technologies that electromagnetic heating can be divided into, namely induction, infrared, microwave and radio-frequency technologies, and ultraviolet (UV) processing. Electromagnetic heating methods produce heat inside the target itself whereas traditional fossil fuel heating heats through convection using a heating medium such as air. Producing heat within a target is very advantageous as it results in faster processing times and therefore also reduces energy use. Like resistive heating, electromagnetic heating methods can reach temperatures high enough for high-temperature processes (up to 3000 °C) and the efficiencies can be as high as 90 %. (Beyond Zero Emissions, 2018)

Induction heating is a heating method used in the processing of metals and other conductive materials. In induction heating the target being processed is inside a metal coil that has an electric current running through it. The current induces an electromagnetic field around the target. This results in an electric current forming within the target generating internal heat. (Beyond Zero Emissions, 2018) The operating principle of induction heating is demonstrated in Figure 3.

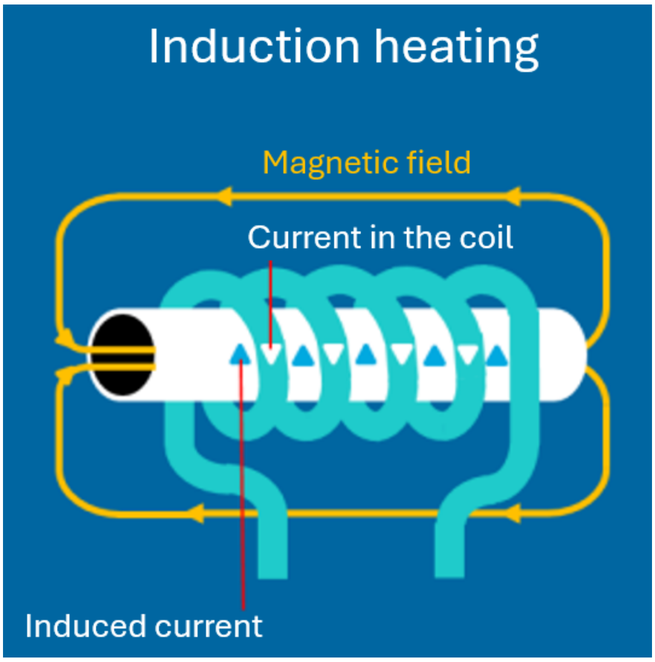

Figure 3. *Working principle of induction heating. (Altered from Jegoroff et al. 2021)*

Compared to traditional gas-fired ovens, that are similar with the ovens used in pressure sensitive label manufacturing, induction heating is fast and efficient, and it heats the target evenly. Induction heating also reduces waste heat and is cleaner than traditional fossil fuel heating methods. (Lucia *et al.* 2014)

Infrared radiation is electromagnetic radiation with a wavelength of 0.7-1000 µm (Tieteen termipankki, 2024). Infrared radiation causes the water molecules in a target to vibrate producing heat. The working principle is similar to the Sun warming the earth. An infrared heating system can be designed based on the heating requirement and the target material characteristics. It can be divided into three different infrared spectrums based on radiation wavelength (Table 2). (Riadh *et al.* 2015)

Table 2. *Three spectrums of infrared heating and their properties. (Altered from Beyond Zero Emissions, 2018)*

	Near infrared	*Medium infrared*	*Far infrared*
Wavelength [µm]	0.76-1.2	1.2-3	3-10
Emitting temperature [°C]	1800-2500	800-1800	400-600
Power density [kw/m^2]	160-300	40-160	10-40
Efficiency [%]	85-95	80-85	50-60

Near infrared is more efficient when drying thicker bodies of material. Far infrared however, is more suited to drying thin layers of material as it is absorbed in the surface of a product. (Riadh *et al.* 2015) Infrared heating is used in food manufacturing (Riadh *et al.* 2015), agricultural processing, drying and curing of coatings and paints and the production of certain plastics. (Beyond Zero Emissions, 2018) It has many of the same advantages as induction heating, for example the speed, cleanliness, and more even heating than fossil fuel convection heating. In addition, infrared heating modules are compact, and they have a modular design, which can make them relatively easy to fit together with other drying technologies (Riadh *et al.* 2015).

Just like the other presented technologies, microwave and radiofrequency systems generate heat within the target material by placing it in an electromagnetic field that causes the molecules in the material to vibrate. Microwaves operate between 900 MHz and 3000 MHz, and radiofrequencies within 10-30 MHz. These technologies work well with materials that don’t conduct electricity and conduct heat poorly making the use of, for example, infrared inefficient. These materials include paper, textile, and wood. (Beyond Zero Emissions, 2018)

UV processing is mainly used in a manufacturing curing process. Curing can be applied to product coatings, adhesives, and inks. UV processing is limited by its need for special, expensive UV-curable coatings. However, just like the other electromagnetic heating methods UV processing is faster and uses less energy than gas-fired solutions. (Beyond Zero Emissions, 2018)

Electrification of an industrial process has many advantages as mentioned before. It can reduce production times, it is cleaner than combusting fossil fuels, it provides more even heating, and the systems respond quite fast to changes. Electrification provides a significant potential for emission reduction especially when renewable electricity is available. While electrification has many advantages, it can also present some problems. Depending on the size of a country’s industrial sector, the amount of electrical transmission and distribution infrastructure would need to be increased in the face of wider electrification of industrial processes. Thiel & Stark (2021) suggest that the amount of electricity in the United States’ grid would have to be doubled to meet the industrial heat demand. In 2018 the electricity grid handled 15 EJ/y of electricity while the natural gas grid handled 11 EJ/y of gas for the industry sector. Additionally, renewable electricity might not always be available, which would reduce the emission reduction potential of electrification.

2.2.2 High-temperature heat pumps

Heat pumps are used to raise lower temperature heat to a higher temperature. This is usually done by using electricity and the thermodynamic properties of different working fluids. Heat can be extracted by changing the pressure and temperature of the working fluid in the system. (IEA, 2023b) The working principle of a heat pump is presented in Figure 4.

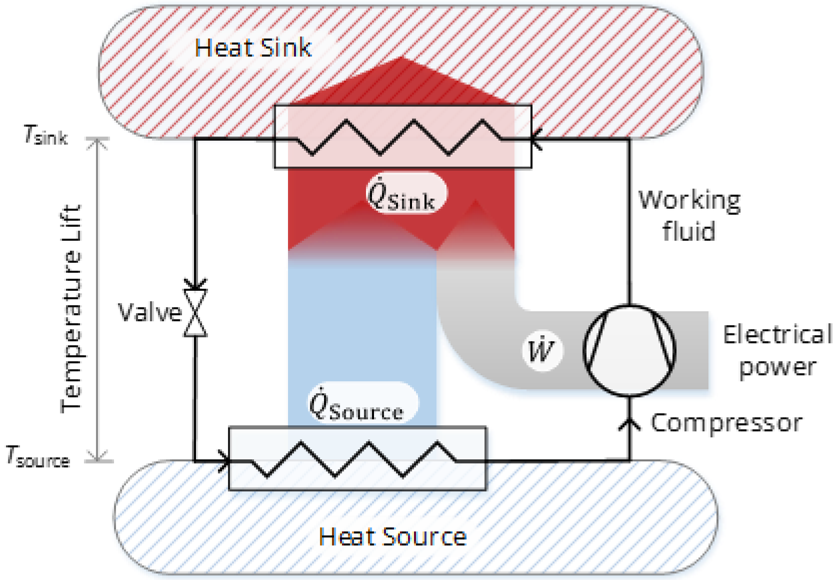

Figure 4. *Working principle of a heat pump. (SuPrHeat, 2014)*

A heat pump has a heat source and a heat sink. A source is the medium where heat is recovered from, and the sink describes the place where heat is supplied to. In a simple cycle there is an electrically driven compressor and an expansion valve between the source and sink, and an evaporator is at the source side, while a condenser is located at the sink side. In the evaporator, the working fluid evaporates as a result of heat transfer from the heat source to the fluid. The working fluid is then compressed with the compressor increasing its temperature and pressure. Afterwards the working fluid goes through the condenser, where the fluid releases energy and condenses, and heat is transferred to the heat sink. The cycle starts again, after the working fluid has expanded in the expansion valve. (IEA, 2022b)

Heat pump technology has been used for a long time, but its applicability has been limited by temperature, as traditional heat pumps only operate in temperatures below 100°C. Through research and development high temperature heat pumps (HTHP) have been developed. The term very high temperature heat pump (VHTHP) has also been introduced in literature. (Klute *et al.* 2024) In this thesis the term VHTHP is not used, and

HTHPs are classified as heat pumps with a sink temperature of 100°C and over. According to Arpagaus *et al.* (2018) HTHPs have great potential especially in the paper, food and chemical industries that have many processes in the 20-200 °C range.

Different heat pump technologies can be divided into open systems and closed systems (Figure 5). In an open cycle a working fluid, also called refrigerant, is not used and instead the process medium itself is ran through the heat pump. In contrast, in a closed-loop system a refrigerant runs through a similar cycle that was described in Figure 4. The process medium runs in its own cycle and is heated without the refrigerant having direct contact with it. (Klute *et al.*, 2024)

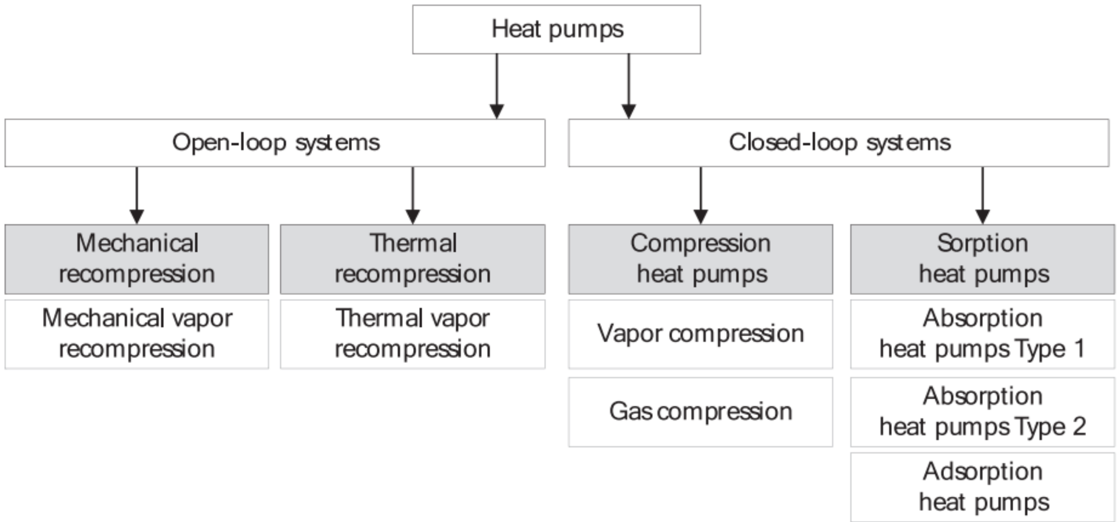

Figure 5. *Classification of heat pump technologies. (Klute et al. 2024)*

As can be seen from the diagram, mechanical vapor recompression and thermal vapor recompression are open-loop systems. They do not use a refrigerant, and instead they upgrade the process medium. These types of heat pumps are typically used to lift process steam to a higher temperature and pressure. In contrast, compression heat pumps and sorption pumps use closed-loop technology. Of compression heat pumps, vapor compression is more commonly used than gas compression. From sorption heat pumps adsorption heat pumps are the least technologically advanced. (Klute *et al.* 2024)

In a 2024 review article Klute *et al.* listed 43 high-temperature, steam generating heat pumps currently in development. Out of these 43, three utilize thermal vapor recompression, three absorption type 2, 10 mechanical vapor recompression, and the remaining 27 are compression heat pumps. The supply temperature range of these heat pumps is 120-350°C with a heat supply capacity of 0.014-100 MW_{th}. Notable is that the highest temperature lifts achieved by these technologies is under 200 °C even with multiple heat transfer stages and many of the technologies have a low technology readiness level

(TRL). Similar results were found in a HTHP review by Arpagaus *et al.* (2018). Higher temperature lifts were not found, and the highest supply temperature (165°C) was achieved for steam generation, while hot air and water production was in the range of 100-120°C.

An important parameter to consider when comparing different HTHP technologies is the coefficient of performance (COP). It demonstrates how many units of heat can be produced with one unit of electricity. (IEA, 2023b) Technologically advanced HTHPs can achieve COP values from 2 up to even 20, but the temperature lift of the heat pump affects the COP. Higher temperature lifts usually require multiple heat transfer stages, which lowers the overall efficiency of the process. Therefore, higher temperature lifts result in lower COPs. In the study by Klute *et al.* (2024) temperature lifts range from 20°C to 170°C. Higher temperature lifts are desired, because they enable the use of lower grade waste heat even for processes that require higher temperatures. (Jiang *et al.* 2022) A good HTHP has a good balance between the possible COP and achievable temperature lift.

HTHPs have many potential applications, and they can be used in many industrial processes as an alternative to fossil fuels. The emission reductions achieved by using HTHPs are heavily dependent on the composition of the electricity mix that is used and the refrigerant. If the electricity mix consists mostly of fossil fuel generated electricity, the emission reductions are lower than when using electricity from renewable sources. (IEA, 2022b)

The used refrigerant can also have an impact on the environment and emissions through leakages. Refrigerants need to have suitable thermal properties (like critical temperature and pressure) for the designed system, but they also need to be environmentally compatible. For example, the ozone depletion potential (ODP) needs to be 0 and the global warming potential (GWP) needs to be as low as possible to reduce any unnecessary impact on the climate. Many chlorofluorocarbons and hydrochlorofluorocarbons have been prohibited due to their high ODP. (IEA, 2022b) In a study by Mateu-Royo *et al.* (2021) different low GWP refrigerants in HTHPs were compared to a high GWP refrigerant and the use of a natural gas boiler. The study found that the equivalent CO_2 emissions could be reduced by 19-63 % using low GWP refrigerants compared to the emissions from a natural gas boiler.

The development of HTHPs is ongoing and many new products are expected to become commercially available in the next couple of years. For lower supply temperatures (up to 120°C) HTHPs are expected to be a "preferred process heating technology" by 2025-

2026 in many industries. For higher supply temperatures a wider commercialization is expected closer to 2030. Development of HTHPs is focused on achieving higher temperature lifts and finding suitable, organic refrigerants. (IEA, 2023b)

2.2.3 Solar thermal

Solar thermal systems convert the Sun’s radiation into thermal energy, that can be used, for example, for process heating. Solar thermal technologies can be categorized in different ways. In this thesis process temperature is an important parameter, and therefore a classification based on system temperature is used (Figure 6). The concentration ratios and temperature ranges of the technologies in Figure 6 are presented below in Table 3.

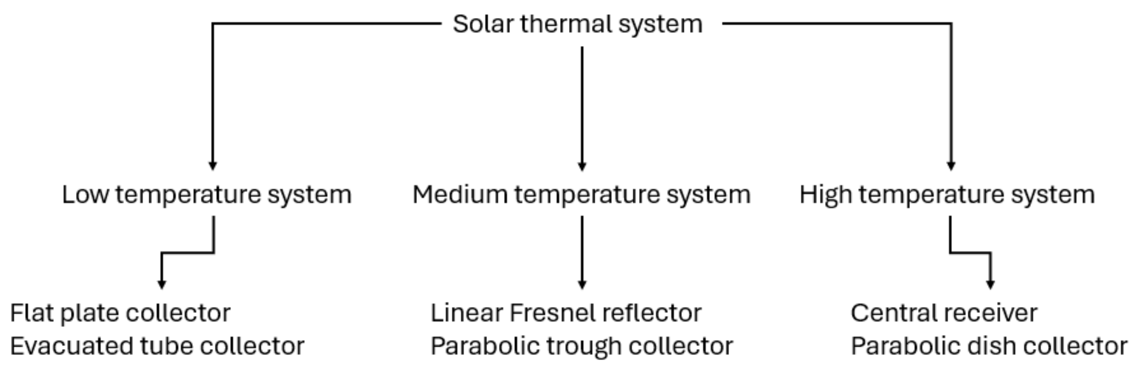

Figure 6. *Selected solar thermal systems categorized by temperature. (Altered from Ravi Kumar et al. 2021)*

Table 3. *Temperature range and concentration ratio of selected solar thermal technologies. (Ravi Kumar et al. 2021)*

Technology	*Temperature [°C]*	*Concentration ratio*
Flat plate collector	< 80	1
Evacuated tube collector	50-120	1
Linear Fresnel reflector	100-300	30-60
Parabolic trough collector	100-400	30-100
Parabolic dish collector	500-1200	100-1000
Central receiver	150-2000	100-1500

Of these technologies flat plate collectors (FPC) and evacuated tube collectors (ETC) are classified as so-called non-concentrating collectors. Non-concentrating collectors are set in a specific angle based on the location of the installation. (Kumar *et al.* 2019) As their name suggests, they do not concentrate the Sun's radiation, and therefore they achieve lower temperatures than concentrating solar thermal technologies. For this reason, they are used in processes that require lower temperatures.

FPCs have a clear cover. Underneath the cover is an absorber plate that absorbs energy. Attached or incorporated to the absorber plate are copper tubes. A heat transfer fluid (HTF) flows through these tubes and receives some of the energy absorbed by the absorber plate. FPCs are mostly suitable for places with a warm and sunny environment, whereas ETCs are more suitable for different kinds of climates. An ETC has many parallel glass tubes that contain their own absorber plates and heat transfer tubes. The air between the glass cover and heat transfer tube is evacuated to reduce heat loss and increase thermal conversion efficiency. (Kumar *et al.* 2019) The operating principle of these non-concentrating collectors is shown below in Figures 7 and 8.

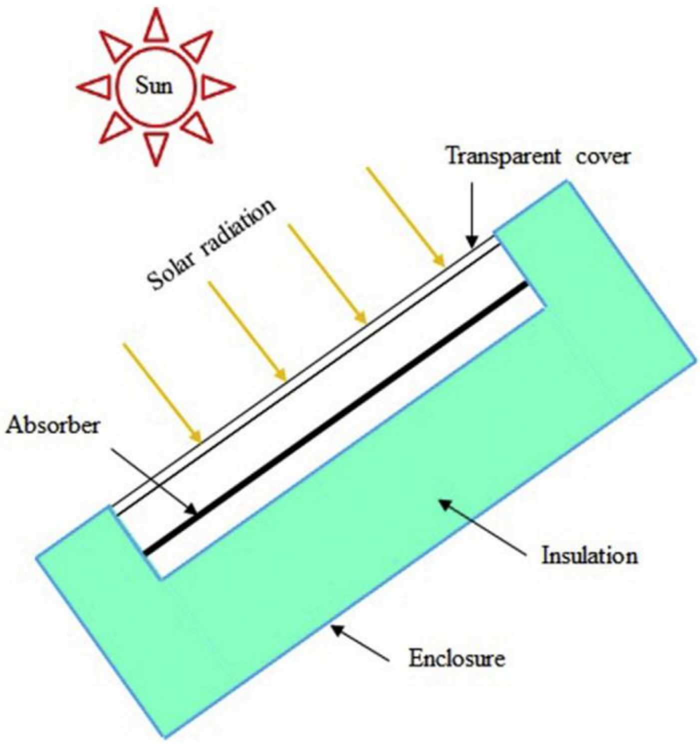

Figure 7. *Working principle of a flat plate collector. (Ravi Kumar et al. 2021)*

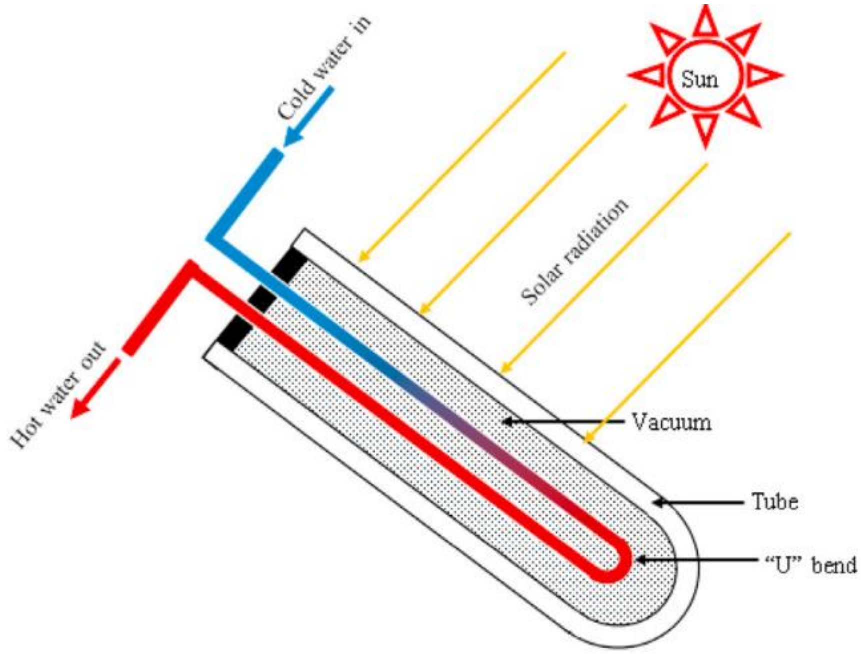

Figure 8. *Working principle of an evacuated tube collector. (Ravi Kumar et al. 2021)*

Concentrating collectors can reach much higher temperatures because they concentrate the radiation on a smaller area reducing heat losses. There are many different technologies of concentrating collectors, but they all consist of concentrators and receivers. Linear Fresnel reflectors (LFR) and parabolic trough collectors (PTC) are concentrating collectors that can provide medium-temperature process heat. A PTC consists of a parabola-shaped, linear reflector and a linear receiver tube that has an absorptive coating. A PTC is usually set in a North-South axis. This enables tracking the sun's movements from East to West using a single-axis tracking system. The ability to track the Sun's movements improves the system's efficiency. PTC is among the most advanced solar thermal technologies for process heating. (Kumar *et al.* 2019)

LFRs cannot achieve concentration rates as high as PTCs and therefore the produced temperature levels are lower, but it is still applicable to medium-temperature heat demand. A LFR has one single receiver and an array of parallel reflectors surrounding it. The receivers can be either curved or flat. The system usually has East-to-West tracking similar to a PTC. (Ravi Kumar *et al.* 2021) A LFR system needs significant amounts of space. The reflectors need to have sufficient space between them to avoid shading each other. However, the system is cheaper than PTC due to a simpler design. (Kumar *et al.* 2019) The working principle of a PTC and a LFR can be seen in Figures 9 and 10.

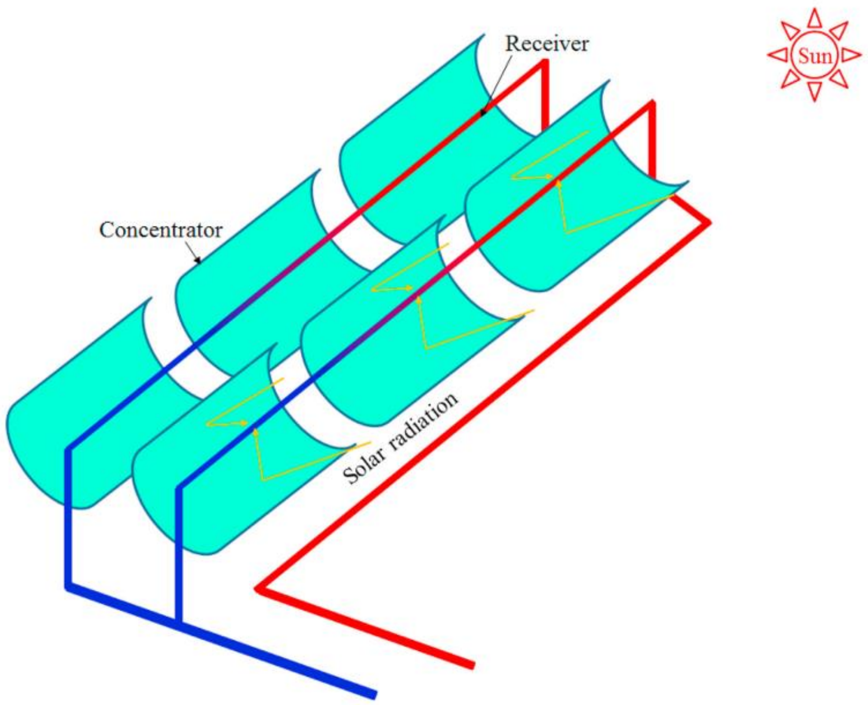

Figure 9. *Working principle of a parabolic trough collector. (Ravi Kumar et al. 2021)*

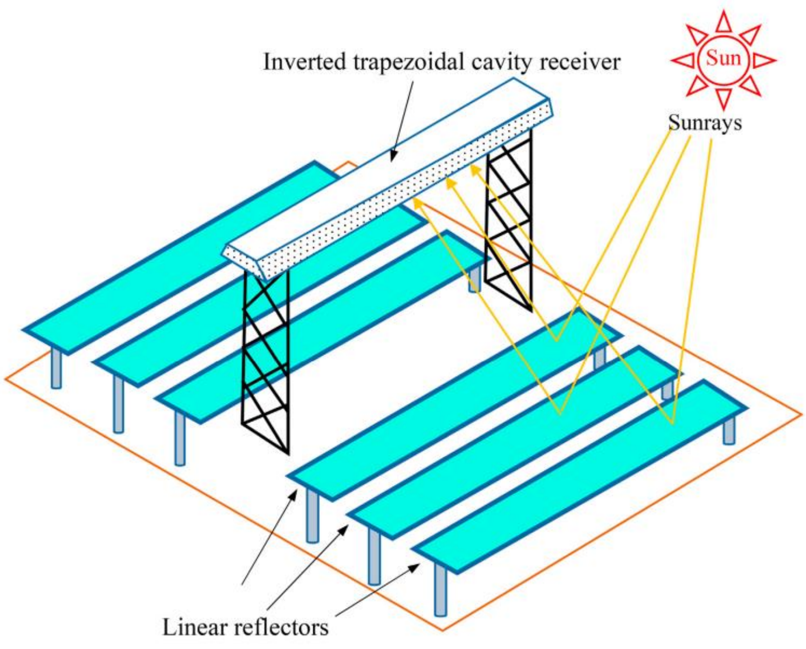

Figure 10. *Working principle of a linear Fresnel reflector. (Ravi Kumar et al. 2021)*

Central receivers and parabolic dish collectors are designed for high-temperature applications. They both use two-axis tracking to achieve maximum concentration on a central receiver. Figures 11 and 12 explain their working principles.

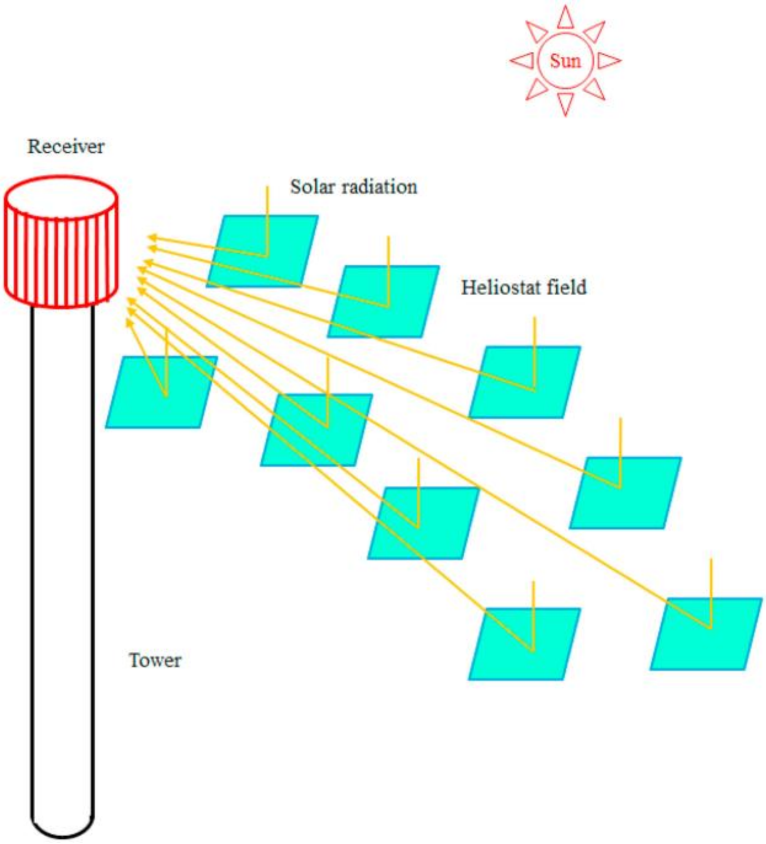

Figure 11. *Working principle of a central receiver. (Ravi Kumar et al. 2021)*

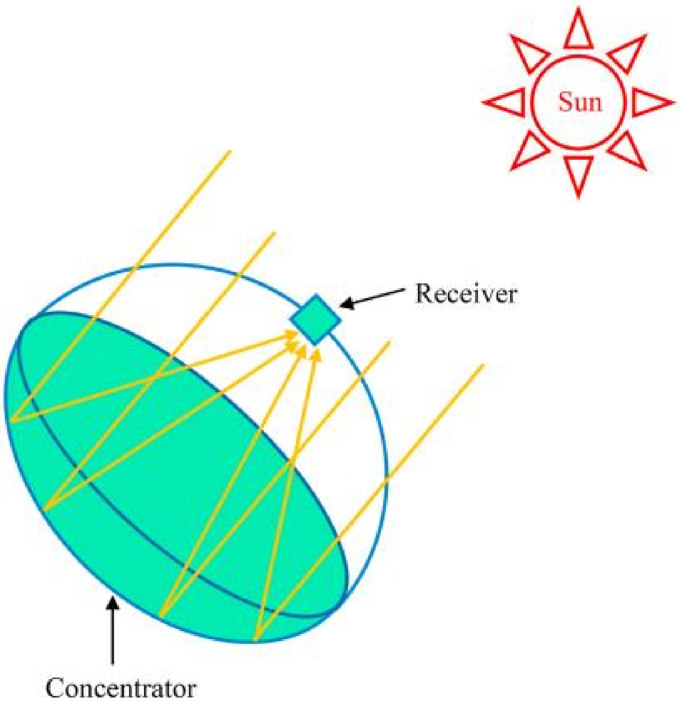

Figure 12. *Working principle of a parabolic dish collector. (Ravi Kumar et al. 2021)*

Despite their many advantages, there are still some challenges in using solar thermal technologies to replace fossil fuels in process heat production. First, there is the availability of space. Solar thermal systems require a substantial amount of space to produce enough heat for a large-scale industrial process. By some estimates 1 km^2 of land could fit 50-60 MW of solar thermal energy (Srivastava & Srivastava, 2013 by Kumar *et al.* 2021). Many industrial processes do not need this much power, but the lack of space can still prevent the installation of a solar collector field. (Ravi Kumar *et al.* 2021) A study by Martínez-Rodríguez *et al.* (2023) found that in a low-temperature system the area of a solar thermal installation was reduced by 85 % if a heat pump was added to the system.

Furthermore, solar radiation is not consistent, and this might present a problem since many industrial processes run around the clock. Weather, season, and time of day all affect the radiation levels hitting the Earth’s surface. This results in fluctuating heat generation and changing temperature of the HTF. This is a problem in terms of process controllability and product quality. As a result, solar thermal systems usually require a backup system or thermal energy storages to compensate for the variation in solar radiation. Precise control technologies and tools to predict solar radiation variation are needed. All the previously mentioned components of the system can increase the capital costs as well as the maintenance costs of the system. It is also notable that solar thermal technologies do not have a thermal efficiency as good as electrification or using a HTHP. Depending on the operating temperature, the efficiency of a solar thermal system can range from 0.34 to 0.84. (Ravi Kumar *et al.* 2021)

2.2.4 Green hydrogen

Hydrogen is the lightest and most abundant element in the universe. It is predicted to have a significant role in the green transition, especially in applications that are deemed difficult to electrify (EASAC, 2023). Hydrogen can be produced by using either non-renewable or renewable sources. Based on the different production methods and the consequential CO_2 emissions, different types of hydrogen are described with different colours. Grey hydrogen typically refers to hydrogen that is produced with a process called steam methane reforming. The production utilizes fossil fuels and does not use carbon capture and storage (CCS) to mitigate the GHG emissions. Green hydrogen, on the other hand, usually refers to hydrogen that has been produced using water electrolysis and renewable electricity. There are multiple additional colours of hydrogen that describe the different sources of energy and production processes used in the manufacturing of hydrogen. (Incer-Valverde *et al.* 2023) For this thesis, the definition of green hydrogen is the most relevant.

The definitions for different coloured hydrogen may vary slightly between sources, but in the EU grey hydrogen is classified as hydrogen produced from fossil fuels. Blue hydrogen is also produced from fossil fuels, but the GHG emissions are reduced with CCS. Green hydrogen is produced of water with electrolysis using renewable electricity. (EASAC, 2023)

Green hydrogen is the most environmentally friendly type of hydrogen as its production does not have GHG emissions. Green hydrogen is produced utilizing a process called electrolysis. In this process (Equation 2) water is separated into oxygen (O_2) and hydrogen (H_2).

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

The working principle of electrolysis includes an anode, cathode, electrolyte, and electricity. The electrolyte carries the produced anions (-) and cations (+) from one electrode to the other. The cations (+) move to the cathode (-) and reduce, while the anions (-) move to the anode (+) and oxidize. H_2 is produced in the cathode and O_2 in the anode. The electric current that runs through the electrolyser cell makes the electrolysis possible. (IRENA, 2020a) The working principle of a certain type of electrolysis is illustrated in Figure 13.

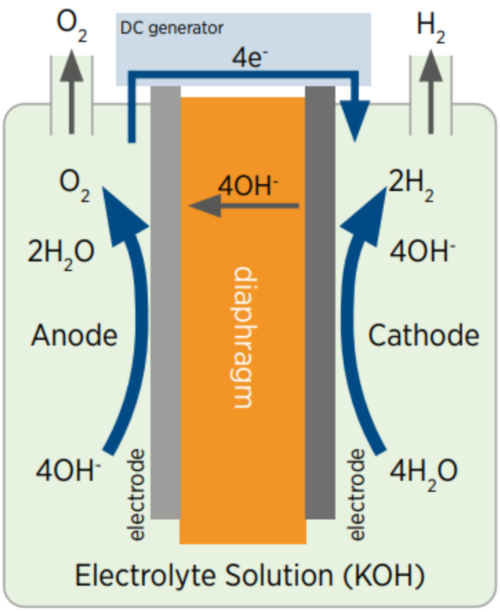

Figure 13. *Working principle of an alkaline water electrolyser. (IRENA, 2020a)*

Currently there are four kinds of electrolysers that are either commonly used or under development. These are alkaline water electrolysers, polymer electrolyte membranes (PEM), anion exchange membranes (AEM), and solid oxide electrolysers (SOE). Alkaline water electrolyser is the most advanced and commonly used technology. PEM, SOE, and AEM are still under development, although PEM is the closest to large-scale commercialization. (Lebrouhi *et al.* 2022) Alkaline water electrolysis, PEM, and AEM have an operating temperature between 40°C and 90°C. SOE, on the other hand, operates in higher temperatures of 700-850°C. (IRENA, 2020a) According to a 2023 study by Incer-Valverde *et al.* the cost of green hydrogen ranges from 1.9 to 8.2 US $\$/kg_{H2}$ depending on the renewable energy source and location of production. For comparison, the cost of steam methane reforming, the most common hydrogen production method, ranges from 0.7 to 2.3 US $\$/kg_{H2}$ being significantly less expensive.

Despite the higher cost, the benefit of all electrolysis processes is that they do not produce harmful side products such as carbon monoxide (CO) or carbon dioxide (CO_2). The production of green hydrogen is the most environmentally friendly, and the direct emissions from production can be stated as 0 kg CO_2eq./kg_{H2}. When considering the whole supply chain (such as the manufacturing of electrolysers and the water used in the process), the emissions range between 0.7-2.8 kg CO_2eq./kg_{H2}. Hydrogen produced with steam methane reforming has direct carbon emissions of 7.5-13 kg CO_2eq./kg_{H2}. (Incer-Valverde *et al.* 2023) In addition, electrolysis also produces cleaner hydrogen than many other production methods. A purity of 99.95 % is possible with electrolysis whereas steam methane reforming can achieve a purity of 94 % and coal gasification only 87 %. Lower purity products need to be purified in a separate process before end-user application. (Newborough & Cooley, 2020)

Regarding the combustion of hydrogen for energy, hydrogen has a very high heating value of 120 MJ/kg compared to natural gas' 50 MJ/kg. However, it also has a low volumetric energy density at only 11 MJ/m^3. The volumetric energy density of natural gas is over three times higher at 35,6 MJ/m^3. Due to the low volumetric energy density, hydrogen needs to be compressed and stored at high pressures (up to 700 bar) for it to be economically viable. An alternative to compression is to store hydrogen in liquid form. At standard pressure this requires a temperature below hydrogen's boiling point of -253 °C. Achieving these low temperatures requires a substantial amount of energy. (Lebrouhi *et al.* 2022)

Switching a fossil fuel such as natural gas for a zero-carbon fuel like hydrogen is a possible option to decarbonize industry. However, hydrogen and natural gas have different physical and chemical properties that need to be considered before switching from one to the other. Since hydrogen is lighter, it needs higher operating pressures than natural gas to deliver the same amount of energy. In addition, hydrogen has a smaller molecular size than natural gas, which may result in more leakages and degradation of the gas grid. Hydrogen also has a wider flammability range and lower ignition energy, which makes it a bigger safety hazard. Due to the different fuel properties many appliances currently using natural gas would have to be modified or replaced if natural gas was switched to pure hydrogen. (Cristello *et al.* 2023)

Alternatively, appliances could be used with a blend of hydrogen and natural gas. According to Cristello *et al.* (2023) many combustion appliances could be used with a blend of up to 25 % hydrogen without having to make major adjustments to the equipment. Using hydrogen enriched natural gas (HENG), however, doesn’t have the same environmental benefits as using pure hydrogen. One study by Mayrhofer *et al.* (2021) on using HENG for industrial heat treatment furnaces found that with a blend of 20 % hydrogen and 80 % natural gas the CO_2 emission reductions were only 6.95 % compared to the use of 100 % natural gas. With a blend of 40 % hydrogen and 60 % natural gas the emission reductions rose to 16.61 %. Many countries don’t allow hydrogen concentrations as high as these in their natural gas grid. For example, in Germany the concentration is limited to 10 %, in France to 6 %, and in the UK to 0 %. (Dolci *et al.* 2019)

As mentioned before, green hydrogen is expensive compared to grey hydrogen. It is also expensive compared to natural gas. According to a 2021 report by the Department for Business, Energy & Industrial strategy of the United Kingdom the price of green hydrogen in 2020 was between 190 €/MWh and 240 €/MWh using grid electricity in industrial retail price. In this scenario the price of hydrogen does not drop below 150 €/MWh even in 2050. According to this report the lowest prices are achieved using curtailed, otherwise wasted, electricity, but even in this scenario the price of hydrogen barely drops below 60 €/MWh. Technological advancements and policy changes need to be done for green hydrogen to compete with the low prices of fossil fuels. In the EU Hydrogen Strategy lower renewable electricity prices, growing carbon prices, and smaller electrolyser costs were identified as key factors to growing the market share of green hydrogen (EASAC, 2023).

Neither C1 nor C2 currently has green hydrogen production. Plans to increase production, however, have been made in both countries. The first green hydrogen production facility in C1 is scheduled to start operation already in 2024. Other pilot projects have also been scheduled to finish construction between 2025 and 2026. (Elinkeinoelämän keskusliitto, 2024) C2 has a hydrogen strategy set for 2030. One goal in this strategy is to have 2 GW of installed low-carbon hydrogen production capacity by 2030. (Ministry of Climate and Environment, 2020)

2.2.5 Synthetic methane

Synthetic methane is a synthetic fuel that is produced from hydrogen (H_2) and carbon dioxide (CO_2) through methanation. (Gorre *et al.* 2019) H_2 for the methanation can be obtained in many ways. Green hydrogen made with renewable electricity through electrolysis is the most environmentally friendly option, and therefore only projects using green hydrogen are examined here. CO_2 for the process can be recovered from a so-called point source, such as a factory's exhaust gas stream, or straight from the air with direct air capture. (Tregambi *et al.* 2023) A simplified process chart of synthetic methane production is presented in Figure 14.

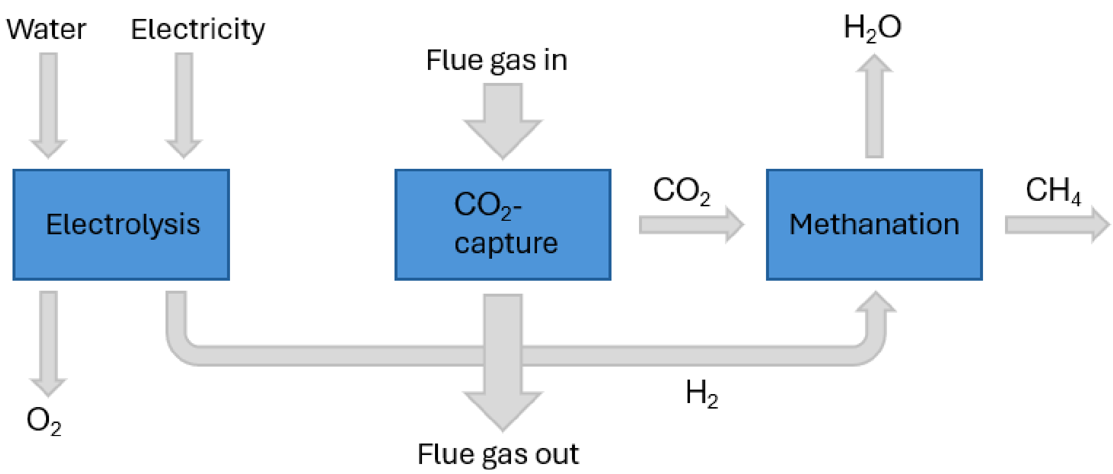

Figure 14. *Production process of synthetic methane. (Altered from Kiani et al. 2021)*

The methanation process can be either catalytic or biological. Catalytic methanation has a process temperature of 200-550 °C and a process pressure of up to 100 bar, while biological methanation requires temperatures between 20°C and 70 °C and pressure up to 10 bar. (Götz *et al.* 2016) The process of CO_2 and H_2 reacting producing methane is called the Sabatier reaction (Equation 3).

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O \quad (3)$$

The Sabatier reaction happens in both catalytic and biological methanation. In catalytic methanation a catalyst metal is used. Metals like cobalt or rhodium can be used, but often nickel is preferred for its good properties as a catalyst and its affordability. In biological methanation there is no need for a catalyst since the methanogens in the process act as auto catalysts. The technology of biological methanation is not yet as advanced as catalytic methanation making catalytic methanation currently a more commonly used method. (Götz *et al.* 2016)

As stated, hydrogen is used in the production of synthetic methane. Having green hydrogen manufacturing plants connected to the grid could help with the issues that the increasing amount of renewables cause. The supply of electricity fluctuates with weather and seasons when using renewables. These fluctuations could be balanced with converting excess electricity into more easily storable energy carriers like hydrogen that can be used further to produce, for example, synthetic methane. (Rola *et al.* 2023)

Using synthetic methane in the place of natural gas is technically a more functional option than hydrogen. Synthetic methane and natural gas are practically indistinguishable by their chemical properties. This allows synthetic methane to be used as a replacement of natural gas without alterations to the natural gas grid or end-use equipment. (Götz *et al.* 2016)

Despite its technological potential, using synthetic methane on a larger scale has some limitations. The production potential of synthetic methane heavily relies on available renewable electricity, the production capacity of green hydrogen, and the availability of CO_2. C1 currently has no own production of synthetic methane. In recent years there have, however, been some investments into synthetic methane production. Some of the projects have since been abandoned, but Koppö Energia Oy is still planning on building a P2X plant. With an electrical input capacity of 200 MW the plant would produce approximately 55 000 tonnes of synthetic methane annually. (EGS Review, 2023) Nordic Ren-Gas Oy has also planned to build a P2X plant in C1. The plant is designed to produce synthetic methane, hydrogen, and district heat. It will be built between 2024-2027 and the annual production of synthetic methane would be 35 tonnes. (Ren-Gas, 2024) In a master's thesis by Pennikangas (2023) about the utilization potential of synthetic methane in C1 he concluded that by 2035 the renewable electricity production will be enough to produce enough synthetic methane to replace natural gas use in C1. In the thesis it was estimated that the production potential of synthetic methane in C1 is good due to the increasing amount of renewable energy and the available biobased CO_2 from the forest industry.

The production of synthetic methane has also been studied in C2. In 2018 TAURON Wytwarzanie announced that it would build a pilot plant for converting CO_2 and H_2 into synthetic methane. The initial test result showed that the plant produced synthetic methane with up to 82 % methane content. (Chwoła *et al.* 2020) However, there is currently no commercial production of synthetic methane in C2 either.

2.2.6 Biomethane

Biogas is a gaseous fuel that is produced through anaerobic digestion (AD) using different kinds of organic raw materials such as crop residue, wastewater, animal manure, and municipal waste (IEA, 2020). The methane content of biogas is 50-75 % and it cannot be injected into the natural gas grid as it is. Biogas can be upgraded into biomethane, that is practically indistinguishable from natural gas. Biomethane has a high methane content and can be distributed through the same infrastructure as natural gas and used in the same end-user applications. (Archana *et al.* 2024)

Despite the similar chemical properties as natural gas, biomethane (a form of bioenergy) is classified as a renewable energy source because the CO_2 emissions released in combustion are then bound again by growing biomass (forests, crops etc.). Therefore, biomethane is classified as a net-zero source of energy that does not add to the emissions of a system. (Motiva, 2024)

The production of biomethane through upgrading biogas first requires the production of biogas. AD is a microbiological process that happens in four stages and results in mix of gases called biogas. First comes hydrolysis during which biopolymers are broken down into monomers, smaller compounds, such as sugars, amino acids, long-chain fatty acids, and glycerol. After hydrolysis comes acidogenesis. During acidogenesis fermentative bacteria use the monomers as a substrate convert them into fermentative intermediates like acetate and CO_2. These volatile fatty acids are then converted into acetate, CO_2, and H_2 in acetogenesis by acetogenic bacteria. The last stage of AD is methanogenesis. This is the reaction where methane is produced. Methane can be produced in two ways: through hydrogenotrophic methanogenesis and acetoclastic methanogenesis. The former uses H_2 as energy to reduce CO_2 into methane, and the latter uses acetate as a substrate to produce methane and CO_2. The result of both is a mixture of CH_4 and CO_2 (with a small part of other gases like NH_3, N_2O, and H_2S), biogas. The portion of other gases depends on the composition of the feedstock that was used in the process. (Archana *et al.* 2024; Ngo *et al.* 2021)

As mentioned, biogas can be upgraded to biomethane to be used as a replacement for natural gas. There are many different upgrading processes that can be used such as water scrubbing, chemical adsorption methods, and membrane separation. (Khan *et al.* 2021) All methods aim to remove the other gases and CO_2 from the gas mix and lift the CH_4 concentration to match the chemical properties of natural gas. The final product injected to the gas grid usually has a 98 % methane content (Gasum, 2024).

Biomethane can also be produced from biomass using a process called gasification. Gasification happens in a high temperature (700-800°C) and pressure, and there is little oxygen in the environment. The feedstock used for biomass gasification is woody biomass such as wood chips. The gasification results in a similar gas mix to AD including H_2, CH_4, and CO. This gas mix is then purified in the methanation process where biomethane is produced. Only around 10 % of produced biomethane around the world is from biomass gasification. (IEA, 2020)

In 2018 only about 8.5 % of biogas was upgraded to biomethane, but 90 % of produced biomethane was from upgrading biogas. However, biomethane production is expected to increase in the upcoming years because it is a more refined product than biogas and it can be utilized in all the existing fossil gas applications. (IEA, 2020) In 2021 3.5 bcm of biomethane was produced in Europe corresponding to around 34 TWh of energy. Even though this is a significant growth from the previous year, it still represents less than 1 % of the natural gas consumption in Europe, and there is still a long way to go to reach the target by the European Commission to produce 35 bcm by 2030. (EBA, 2024)

In 2022 about 200 GWh of biomethane was produced in C1 in a total of 26 processing plants (SBB, 2023). During the same year natural gas consumption was 11,9 TWh in C1 (Energiavirasto, 2023a). Even with the decreasing consumption of natural gas due to increasing prices and breaking away from Russian natural gas, the biomethane production is currently unable to cover the consumption of natural gas. Based on new investments the production capacity of biomethane is expected to rise over 1 TWh by 2026 (SBB, 2023). In a 2022 publication by Guidehouse and Gas for Climate C1's biomethane potential was estimated to be around 6.8 TWh by 2030 and 66 TWh by 2050. Thermal gasification potential was estimated to be much higher than anaerobic digestion potential in the long run mainly because of the high quantities of wood waste and forestry residues.

In the same report by Guidehouse (2022) C2's potential for biomethane production was estimated to be around 32 TWh in 2030 and 115 TWh by 2050. As mentioned before, in 2021 C2's natural gas consumption was approximately 185 TWh. By this estimation by 2030 approximately 17 % of C2's natural gas consumption could be replaced by biomethane, but realizing this potential of course requires willingness from the government and investors.

In the IEA 2020 outlook for biogas and biomethane it is estimated that the cost of producing biomethane through upgrading biogas is currently about 19 USD/MBtu or 60 €/MWh. Most of the price comes from producing the biogas itself. According to this estimate the upgrading process price ranges from 2 USD/MBtu to 4 USD/MBtu. The upgrading price heavily depends on the region and production capacity. The report evaluates that by 2040 the average price of biomethane production to be around 14 USD/MBtu or 44 €/MWh. Carbon pricing and crediting avoided methane emissions can increase the price competitiveness of biomethane. (IEA, 2020)

2.2.7 Carbon Capture and Storage

Carbon capture and storage (CCS) refers to a range of different technologies that can capture carbon either before or after combustion, or straight from the atmosphere. The goal of CCS is to reduce carbon emissions from different processes, especially ones that are otherwise hard to decarbonize. (IEA, 2024a) Using CCS with energy sources such as sustainable biomass can in theory result in negative emissions due to bioenergy already being a net-zero source of energy. (Global CCS Institute, 2023)

CCS technologies can be categorized into three groups. Pre-combustion technologies capture carbon from the fuel before combustion happens. With these technologies the captured stream usually has a higher CO_2 content compared to post-combustion techniques. Higher CO_2 content lowers the CCS costs. (Karjunen, 2022)

Post-combustion carbon capture technologies separate the CO_2 form flue gas after combustion. Post-combustion technologies are more widely used since they can be retrofitted to existing processes more easily than the other two technologies. There is a plethora of different post-combustion capture technologies. They can be loosely categorized into three groups: adsorption, absorption, and membrane separation technologies. Absorption is the most used and mature post-combustion CCS technology as 57 % of deployed post-combustion CCS uses absorption. (Karjunen, 2022)

Oxy-fuel combustion capture happens after the combustion. The difference to post-combustion technologies is that instead of air and fuel oxygen and fuel are fed into the combustion reaction. Since nitrogen is removed from the process air the flue gas mostly consists of CO_2 and H_2O making the carbon capture process much easier. The challenge of oxy-fuel combustion is the energy required to produce oxygen for the process. The separation of oxygen can consume up to 60 % of the total energy needed for the CCS. (Karjunen, 2022)

Currently 65 % of operating CO_2 capture capacity is used in natural gas processing, where CCS is affordable. Only 8 % of deployed CCS was used in industry excluding the cement and iron and steel industry, and power and heat production. (IEA, 2024a) In his doctoral thesis Karjunen (2022) predicts that in the industry sector cement, steel, chemical, and pulp and paper industries will present most potential for CCS. These industries have large unit sizes, their flue gases have high concentrations of CO_2, and their operation is relatively stable. All these factors result in lower cost for CCS. Currently the cost of carbon capture is in the range of 60-300 USD/tCO_2. The price depends on the process conditions such as the scale of production, the partial pressure of CO_2, and the total pressure of flue gases. (Global CCS Institute, 2021) Price is not the only thing that limits the deployment of CCS. Many CCS technologies are only able to promise a CO_2 capture rate up to 95 % and are still not commercial. (Global CCS Institute, 2023)

2.2.8 Thermal storages

Thermal storages on their own cannot be used to decarbonize an industrial process. However, thermal storages may need to be installed to aid certain decarbonization solutions. For example, solar thermal installations may need a thermal storage system if process heat needs to be provided around the clock. Thermal storages can also be installed to minimize a system's operational costs. If a system has been electrified, for example, a thermal storage can be installed to be used when electricity is very expensive. For this reason, a short description of the most common thermal storages is given in this chapter.

So-called sensible heat storages are the most common thermal storage systems because the technology is well developed, they are simple, and more affordable than many other storage types. Sensible heat storages use a storage medium like water or molten salt to store thermal energy. Alternatively, the storage medium can be in solid form (bricks, sand, etc.). The operating temperature ranges anywhere from -160°C to 1300°C. Sensible heat storages usually require a lot of space, and they might need further insulation or energy input to maintain the stored thermal energy. (IRENA, 2020b)

Latent heat storages use so-called phase-change materials (PCM) to store thermal energy. PCMs use the latent heat needed for the phase change of a material. The thermophysical properties of a PCM should be considered when selecting the PCM. The phase-change temperature is the most important criterion, but also properties like thermal conductivity should be considered. Due to PCM's higher energy density compared to sensible heat storage materials the latent heat storage systems are often smaller. These applications are especially useful in processes that need a constant, specific output temperature. (IRENA, 2020b)

Thermochemical heat storages utilize chemical reactions of two different substances to store heat. Many of these technologies present a potential for long-term, seasonal heat storage and are developed with that in mind. Thermochemical heat storages have a wide temperature range for application, but they are not as efficient as many other systems. (IRENA, 2020b)

2.2.9 Possibilities for integrating fossil-free heat sources in industry

Above, many potential technologies for replacing the use of natural gas in industry were presented. As previously mentioned, the industry sector has large variation and therefore different solutions work for different manufacturers and processes. The most suitable form of decarbonization depends on matters such as the temperature requirements for manufacturing, the location and infrastructure around the manufacturing facility, required thermal power, the investment cost and operational costs of the system, and the available space inside or outside the manufacturing facility. Next, some real-life examples from different industries are presented to illustrate how natural gas can be replaced in specific processes.

Valio, a Finnish food manufacturer mainly focused on producing dairy products, reduced the use of natural gas in their factory in Riihimäki in 2022 via electrification. Previously, natural gas boilers were used in the factory for heat production. However, in 2022 the old natural gas boilers were replaced with an electric boiler that has a higher efficiency and reduced carbon dioxide emissions. The electric boiler provides heat for the heat treatment of fresh product, washing, and for heating the factory. Based on the article published in October of 2022 the electric boiler was not running on fully carbon-neutral electricity in 2022. To get the full emission reductions of 1 700 tons of CO_2/a compared to natural gas combustion the electric boiler would have to run only on carbon-neutral electricity. (Valio, 2022)

In 2019 a high temperature heat pump demonstration project was started in a brick production factory in Austria. A high-temperature heat pump was installed in place of a 300 kW natural gas burner for waste heat recovery. The heat pump provided hot air from 120 °C up to 160 °C for the brick drying process where the water content of bricks is reduced from 28 % to 2 % before they are fired in a kiln. The heat source for the heat pump was water at 90 °C. (Wilk *et al.* 2020) The process can be seen below in Figure 15.

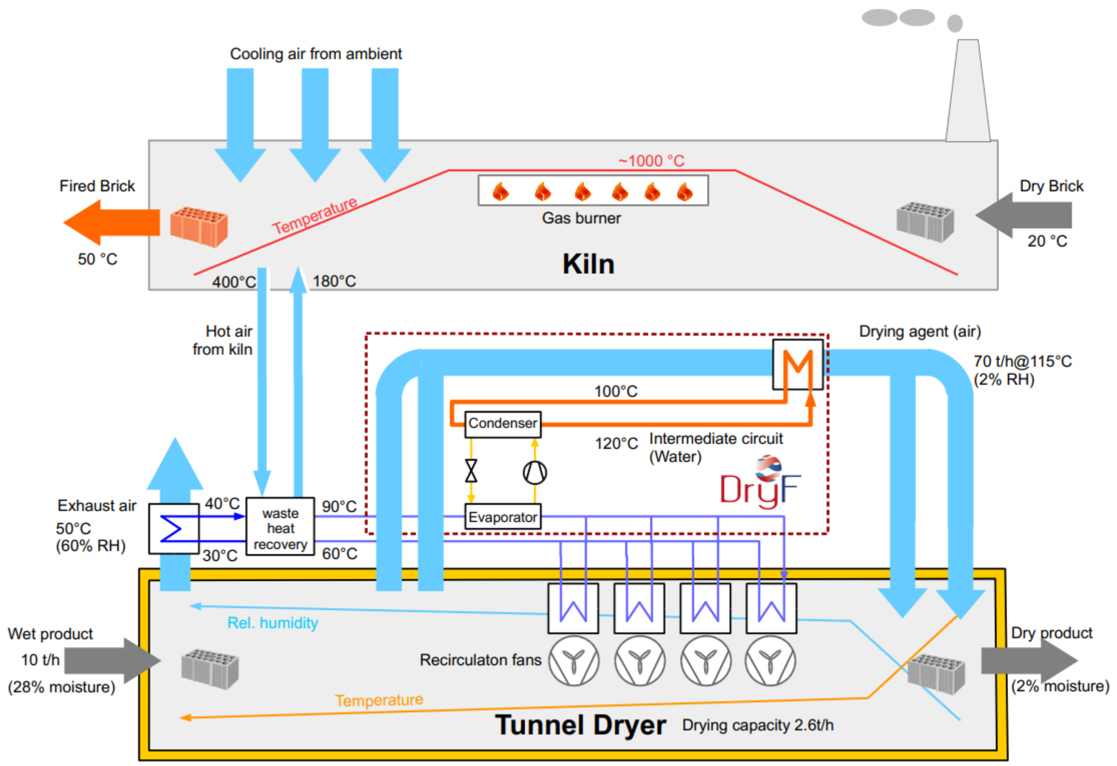

Figure 15. *Process chart of a brick production process with a high-temperature heat pump for heat recovery. (Wilk et al. 2020)*

The demonstration project showed that cost and emission reductions were achieved with using the heat pump compared to the reference case of the gas burner. The COP of the heat pump was at its highest (4.65) when the supply temperature was 120 °C. With the highest supply temperature of 160 °C the COP dropped to 2.66. The energy and emission reductions were also at their highest with the lower temperature lift (approximately 80 %) even though reductions also occurred for the larger temperature lift (approximately 67 %). The demonstration results also indicated that the CO_2 price had a big impact on the overall energy cost reductions especially with the higher temperature lifts. (Wilk *et al.* 2020)

In September of 2023 Avery Dennison, a big operator in the pressure sensitive label business, announced that it had commissioned a concentrated solar thermal system in its production plant in Turnhout, Belgium. The installed solar field has a peak energy yield of 2.7 GWh_{th} and it requires an installation space of 5 540 m^2 on site. The system also includes six thermal storage modules that have a thermal power capacity of 5 MWh. The solar field has parabolic mirrors that concentrate the Sun's energy to a collector tube with heat transfer fluid. The system is meant to reduce the natural gas consumption of the production plant, and it is estimated to provide an equivalent of 2.3 GWh of natural gas consumption. The annual reductions in greenhouse gas emissions are estimated to be 9 % on average, and in high-sunshine periods the solar thermal system will cover the whole heat demand of the plant. (Avery Dennison, 2023)

2.3 Summary

Natural gas in process heat production can be replaced by an array of technologies. Industrial processes are a very heterogeneous group, and one solution does not suit all processes making industry very hard to decarbonize. In table 4, the technologies presented earlier in this chapter are summarized by their key advantages and disadvantages.

Table 4a. *Summary of previously presented technologies.*

Technology	*Characteristics of technology*
Electrification	Thermal power: dependent on the solution Temperature range: ~ 100-3000 °C (Beyond Zero Emissions, 2018) Thermal efficiency: ~ 50-100 % (Beyond Zero Emissions, 2018) Advantages: range of commercial solutions, no direct emissions, clean heating Disadvantages: emission reductions dependent on source of electricity, availability of green electricity, grid capacity and flexibility need to be expanded in the face of wider electrification
HTHP	Thermal power: ~ 0.1-10 MW (IEA, 2023b) Temperature range: ~ 100-200 °C (IEA, 2023b) COP: ~ 1-20 (IEA, 2023b) Advantages: high thermal efficiency, no direct emissions, clean heating Disadvantages: developing technology, emission reductions dependent on source of electricity, availability of green electricity
Solar thermal	Thermal power: dependent on installed collector area Temperature range: ~ 50-2000 °C (Kumar *et al.* 2019) Thermal efficiency: ~ 34-85 % (Ravi Kumar *et al.* 2021) Advantages: commercial solutions available, option for developing areas where other solutions (like electricity) are not available, clean heating Disadvantages: production dependent on conditions, energy storage/parallel heating system required for around-the-clock heat production, large installations can be expensive, thermal efficiency comparatively low

***Table 4b.** Summary of previously presented technologies.*

Technology	*Characteristics of technology*
Hydrogen	Thermal power: ~ 0.5-90 MW (Oilon, 2022) Temperature range: up to 1600 °C (Honeywell, 2017) Thermal efficiency: ~ 70-90 % (Honeywell, 2017) Advantages: no emissions from combustion, current natural gas system can possibly be modified to accommodate hydrogen, option to burn a mix of hydrogen and natural gas Disadvantages: no current production, electrolysis is expensive, additional safety concerns due to higher flammability than natural gas, pure hydrogen burners not as mature as NG burners
Synthetic methane	Thermal power: ~ 0.5-90 MW (Oilon, 2022) Temperature range: up to 1600 °C (Honeywell, 2017) Thermal efficiency: ~ 70-90 % (Honeywell, 2017 Advantages: direct replacement for natural gas → no modifications to current manufacturing process Disadvantages: no current production, more expensive than natural gas, availability of green hydrogen and CO_2 for production
Biomethane	Thermal power: ~ 0.5-90 MW (Oilon, 2022) Temperature range: up to 1600 °C (Honeywell, 2017) Thermal efficiency: ~ 70-90 % (Honeywell, 2017) Advantages: direct replacement for natural gas → no modifications to current manufacturing process, emission factor 0 Disadvantages: very limited production, more expensive than natural gas
CCS	Advantages: for large facilities with large flue gas volumes, captured CO_2 can be utilized or possibly sold Disadvantages: expensive, requires large-scale capture to be feasible, limits for CO_2 concentration in flue gas, capture facility needs a large space, no 100 % capture rate

What was found in the literary research is that there are three distinct categories of technologies that are used in decarbonizing industries. Electrification (including HTHPs) is presented as perhaps the most potential option, while alternative fuels and other technologies such as solar thermal and CCS are solutions for processes where electrification is not possible.

Electrification has many advantages such as a good thermal efficiency, even heating, no dirt from combustion, and a reduction in emissions. There are already commercial solutions for electrification, and there is a rise in the production of renewable energy, which supports the electrification of industry. It is essential that green electricity is available when electrifying an industrial process, since emissions can grow if “dirty” electricity is used.

Alternative fuels can be a low-effort way to decarbonize an industrial process where natural gas is used, since big investments in new infrastructure would not necessarily be needed. Due to their similar chemical properties to natural gas, synthetic methane and biomethane could replace natural gas with minimal changes. In terms of investment costs this can be a more affordable solution than investing in a completely new heating system. However, alternative fuels are not available everywhere as mentioned in previous chapters. Many projects are in development, and the up-coming years will likely show how widespread the use of alternative fuels will be. In Table 4b the thermal power, efficiency and temperature range were estimated based on two burner manufacturers’ information. Notable is that even though some manufacturers list hydrogen as a possible fuel for their burners, all natural gas burners may not be suitable for pure hydrogen.

Solar thermal technologies present great potential especially in areas where other solutions are not available. The temperature range between the technologies is wide although solar thermal is mostly used for low- and medium-temperature applications. There are also matters that slow down the use of solar thermal technologies: bigger installations require a lot of space and can become very expensive, the heat production is related to conditions and solar thermal is not profitable all over the world, and if a process needs process heat around the clock a solar thermal system will need energy storages or another parallel heating system to be able to provide that. These matters contribute to solar thermal not being efficient- or feasible-enough for all industries.

Similarly to solar thermal technologies, CCS is a solution for situations where other solutions do not work, or the process conditions happen to be optimal for CCS. As stated, CCS usually requires large volumes of flue gas with a high-enough concentration of CO_2 to be feasible. For this reason, CCS is mostly deployed in industries like steel, chemical, and pulp and paper. Even though there is development for more modular solutions that could work in smaller facilities, the main direction of development for CCS is still to use the economics of scale to make the technology more feasible.

3. TECHNO-ECONOMIC ASSESSMENT OF NATURAL GAS ALTERNATIVES

In this chapter a breakdown of the calculation methods used in the economic and environmental studies are presented. These calculation methods will be used later in the thesis to calculate the feasibility and environmental impact of investing in natural gas alternatives.

3.1 Techno-economic calculation methods

Assessing the profitability of an investment is key before making a final investment decision. The profitability of an investment can be examined using different calculation methods and key values. One of the simpler methods is to calculate the interest-free investment payback time. This is called the payback method. This method does not consider the time value of money. It simply gives the amount of time it takes for the initial investment to be paid back. (Gazely & Lambert, 2006) The payback time can be calculated by dividing the initial investment cost by the annual average cash flow (Equation 4).

$$Payback\ time = \frac{investment\ cost}{annual\ average\ cash\ flow} \tag{4}$$

The shorter the payback time, the better the investment is according to the payback method. This method is good in evaluating the near-future cash flows of the investment. This is useful especially in an uncertain environment, where cash flows further in the future may be very uncertain and it is risky to base an investment decision on those. The payback method is usually used together with other economic calculation methods, and companies often have a predetermined value for the payback time that can't be crossed, for example 3 years. Annual discounted cash flows can also be used to calculate the payback time to avoid some of the shortcomings of the payback method. (Ikäheimo *et al.* 2019)

Internal rate of return (IRR) is another investment feasibility calculation method. Unlike the payback method, IRR considers the time value of money. This method delivers the profit on the capital investment in percents. It can also be expressed as a discount rate with which the net present value (NPV) of an investment is zero. (Gazely & Lambert, 2006) The IRR can be calculated using Equation 5,

$$0 = \sum_{t=1}^{n} \frac{NCF_t}{(1+IRR)^t} + \frac{I_n}{(1+IRR)^n} - I_0 \tag{5}$$

Where NCF_t is the annual net cash flow, I_n is the depreciation value of the investment, I_0 is the investment cost, n is the lifetime of the investment, and t is time (usually in years). Based on the IRR method, the best investment is the investment with the highest IRR. (Ikäheimo *et al.* 2019) Companies usually have a hurdle rate for investments. If the IRR is lower than this hurdle rate, the investment is not cost-effective. When calculating the IRR, it needs to be acknowledged that the IRR only tells the profit percentage and not the absolute profit as a unit of currency. Therefore, it might sometimes be more advisable for a company to invest in a project with a lower IRR but with higher absolute profits. This is one example of why it is common to use different investment calculation methods together when making an investment decision. (Vipond, 2024)

In the net present value (NPV) method all payments are discounted to the same moment (usually the starting point of the investment). The investment is profitable if the NPV of all cash flows is positive. The difference of NPV compared to the IRR method is that the result is given in currency rather than a percentage. (Ikäheimo *et al.* 2019) The equation for calculating the present value factor (PVF) is below.

$$PVF = \frac{1}{(1+i)^n} \tag{6}$$

Here i is the hurdle rate, and n is the lifetime of the investment. Using the PVF the NPV can then be calculated with the following equation. (Ikäheimo *et al.* 2019)

$$NPV = PVF(net\ cash\ flow - investment\ cost) \tag{7}$$

NPV can also be calculated using the discount rate as follows.

$$NPV = \sum_{t=1}^{n} \frac{NCF_t}{(1+r)^t} + \frac{I_n}{(1+r)^t} - I_0 \tag{8}$$

In Equation 8, r is the discount rate. Theoretically a company should execute all investment projects with a positive NPV. However, this is practically impossible since it is very unusual for a company to have unlimited investment funds.

Additionally, to the previously mentioned methods a return on investment (ROI) can also be calculated (Equation 9). ROI is used when assessing the effect of the investment on the return on capital. It is a simplified version of the IRR method. It does not acknowledge the time value of money or examine cash flows. (CFI, 2024)

$$ROI = \frac{investment\ profits - investment\ costs - writeoffs}{investment\ costs} \tag{9}$$

All the methods of calculating an investments profitability have their own strengths and weaknesses as described before. Therefore, it is beneficial to use at least some of these methods together to find the investment that is the most profitable for the company.

One of the objectives of this thesis is to calculate the environmental benefits that decarbonizing the drying line would have. Environmental benefits refer to the amount of GHG emissions that could be avoided with decarbonization. In addition to the amount of abated emissions, it is also beneficial to calculate the cost for carbon abatement. Calculating the levelized cost of carbon abatement (LCCA) with Equation 10 is a good way to do this.

$$LCCA = \frac{C}{E_0 - E_1} \tag{10}$$

In Equation 10, C refers to the change in costs when a new system is implemented. E_0 represents the emissions from the original system, whereas E_1 is the emissions from the new system. Utilizing Equation 10 a cost for carbon abatement is received as currency per unit of reduction. This equation is a very simplified way of calculating LCCA, and it can be specified to match the accuracy of data and other calculations. (Friedmann *et al.* 2020)

To avoid discrepancies when calculating LCCA, the GHG emissions need to be mapped out for both the old and the new system. (Friedmann *et al.* 2020) Utilizing the scopes set by Greenhouse gas protocol is a good way to map out the emissions used in calculating LCCA. GHG protocol divides a company's emissions into three scopes. The division is done by where in the production chain the emissions occur. Scope 1 measures the direct emissions from the company-owned actions, for example, combusting fuels in a company's own manufacturing facility. Direct emissions of combusting biomass are not included in this. (GHG Protocol, 2015)

Scope 2 is also directly related to a company's manufacturing process as it measures the emissions that occur from the generation of electricity that is then purchased and used by the company. The emissions do not physically occur at the company's manufacturing site but are still an important part of a company's emissions. (GHG Protocol, 2015)

Scope 3 differs from scope 1 and 2 in that it measures emissions from sources that are not owned or controlled by the company including any transportation that is required in the manufacturing and selling of a product and extracting the raw materials for manufacturing. Scope 3 emissions are indirect and reporting them is optional. Companies usually focus on reducing scope 1 and 2 emissions first as is also done in this thesis. (GHG Protocol, 2015)

4. MATERIALS AND METHODS

In this chapter the methods for finding the most suitable alternative for natural gas in pressure sensitive label manufacturing are presented. First, the research strategy is presented followed with a process description of the label manufacturing process. Then the different technologies found in the literature study are ranked based on selected criteria. Of these technologies the top two best suited technologies are then examined in a more in-depth economic and environmental study. The starting values for the investment and emission reduction calculations are detailed with the aim that with the values and methods given in this chapter the calculations in this thesis can be replicated.

4.1 Research strategy

The objective of this thesis was to map out technologies that are used to decarbonize different industries, evaluate which of these technologies would suit the pressure sensitive label manufacturing process the best, and finally assess the economic and environmental effects of these solutions. The pathway to reach these objectives is presented in Figure 16.

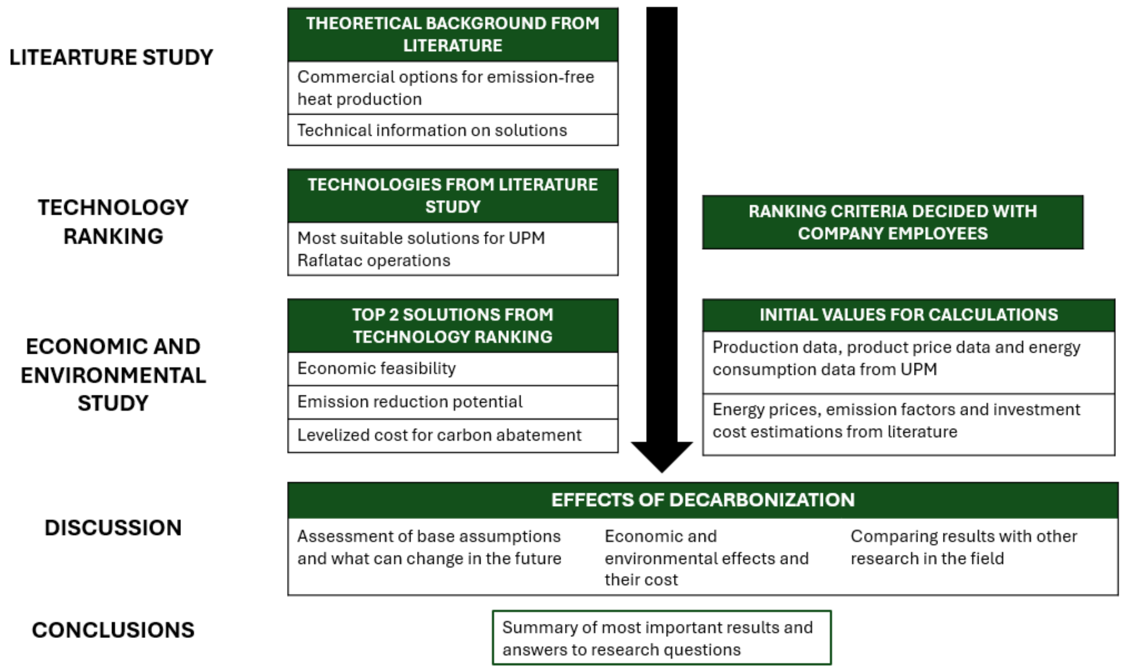

Figure 16. *Visualization of the research strategy.*

The thesis can be divided into three distinct parts the first part being a literature study where different options for replacing natural gas were investigated. The goal of the literature study was to present UPM Raflatac with a comprehensive understanding of what technologies are already being used to decarbonize different industries, and what technologies can possibly be used for this purpose but are not yet deployed on a commercial scale. Because UPM Raflatac has emission reduction goals set for 2030, the most common solutions currently used were selected for the technical evaluation.

The second part of this thesis is a technical evaluation of the solutions that were found in the literature study. The objective here is to evaluate the selected solutions from the point of view of the specific manufacturing process in the UPM Raflatac factories. The technical evaluation was done based on a set of criteria that were carefully selected with employees at UPM Raflatac who are familiar with the label manufacturing process. With these criteria the technologies were evaluated based on either literary sources or the first-hand experience of the staff at UPM Raflatac.

The technical evaluation cut down the number of technologies as only the two highest ranked solutions for both case studies were selected for the economic and environmental study. The economic feasibility was assessed based on investment NPV and payback time as described in Chapter 3. The environmental benefits were examined through emission reduction potential, and a levelized cost of carbon abatement for all solutions was also calculated. The starting values for calculations were either based on literary sources or data from the factories.

4.2 Process description

Pressure sensitive label products are manufactured in a multiphase coating process. In this chapter the whole manufacturing process is presented on a general level. As the drying process is the focus of this thesis, it is described in more detail. The information in this chapter was obtained from UPM Raflatac documents and employees.

At its simplest, a pressure sensitive label consists of four different layered components. There is a release liner, silicone layer, adhesive layer and a face material. The face material and adhesive make up the functional part of a label, and the release liner and silicone give the label a surface to adhere to before use. To give the label different properties, the layers may also include a primer layer and top coat (Figure 17).

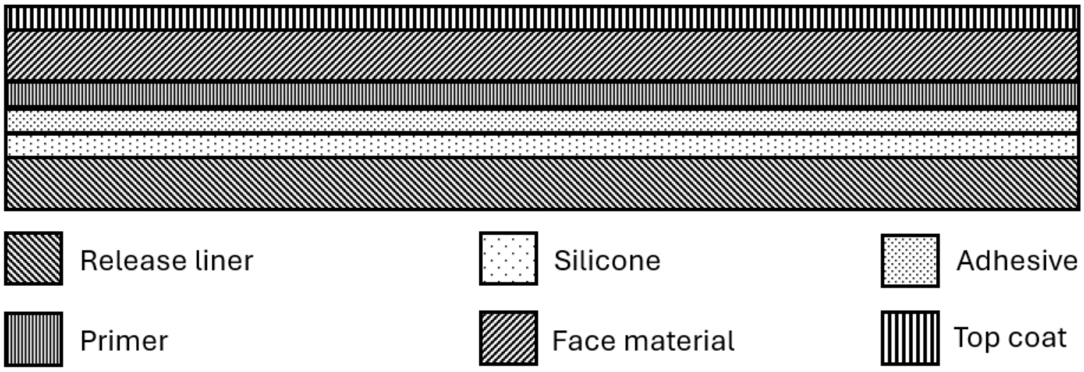

Figure 17. *Structure of a pressure sensitive label.*

The release liner that can be seen in the picture above is the structural element on which the product is made upon. The whole route of the release liner throughout the manufacturing process can be seen in the simplified process chart in Figure 18.

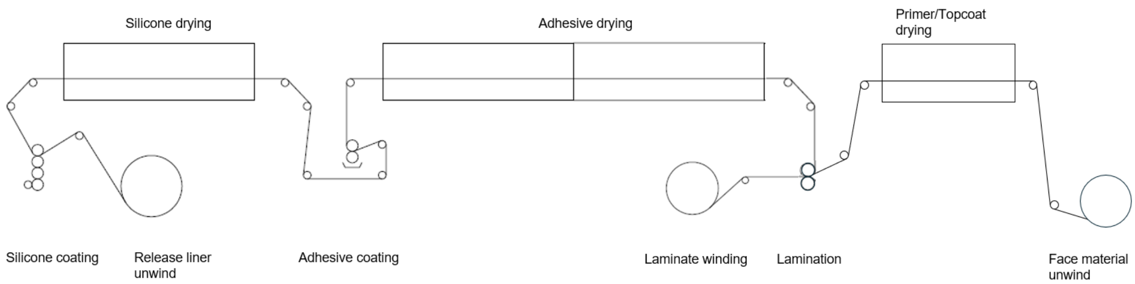

Figure 18. *Manufacturing process of pressure sensitive label.*

The release liner is first unwound with an unwinder. From there the liner is taken to a silicone station, where a thin layer of silicone is applied on top of the release liner. This enables the pressure sensitive label to be opened without the adhesive getting stuck on the release liner. After application, the silicone needs to be activated. This is done in a curing oven that uses hot air for the silicone activation. Gas burners are used to provide process heat to the curing oven.

After the curing oven, the web is led to an adhesive coating station where a layer of adhesive is applied on top of the silicone layer. The coating machines that are studied in this thesis use water-based adhesives. These kinds of adhesives require drying after application as they contain approximately 50 % of water. For the adhesive to work as intended, most of the water in the adhesive needs to be removed. This happens in a drying tunnel where the water content of the adhesive is vaporized using hot air. After the water has been vaporized, the release liner is ready to be laminated together with the face material.

The face material is unwound with an unwinder just like the release liner. After unwinding, a layer of primer can be applied, but it is not necessary for all products. If a primer is used, the face material also needs to be dried in a separate drying process. After unwinding and a possible layer of primer and drying, the face material is led to a lamination nip together with the release liner. At the lamination nip, the two components of a pressure sensitive label are joined to make a complete product as depicted in Figure 18. The complete label is then rewound with a rewinder to make an easy-to-handle jumbo roll.

Natural gas is used in the curing of silicone, adhesive drying, and drying the primer and topcoat. These parts of the process require process heat that is currently produced by burning natural gas or liquefied petroleum gas in gas burners. The energy consumption of the manufacturing process heavily depends on the size of the coating machine. A process flow chart of the adhesive drying is presented in Figure 19.

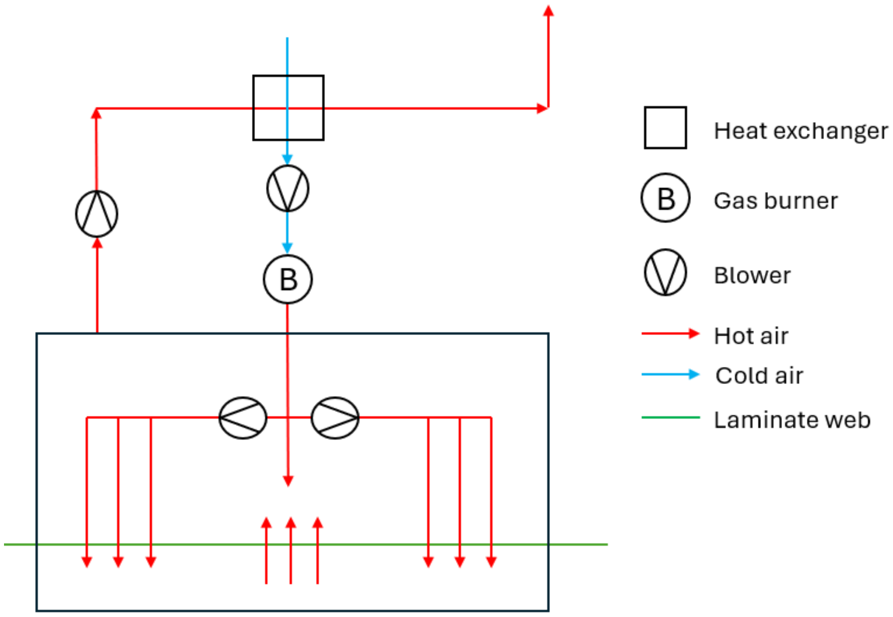

Figure 19. *Current working principle of a drying oven.*

The heated air flows through the process as shown above. Air is taken either from the machinery hall or outside. The fresh air is preheated with the exit stream in a heat exchanger, and after the heat exchanger, the air is then heated up to process temperature with gas burners. Once the correct temperature is reached, the process air is circulated through the dryers as can be seen from the process flow chart. A small portion of air needs to be constantly removed and replaced to keep the air humidity inside the drying ovens at a desired level. Each dryer has an integrated gas burner that heats the dryer inlet air. A dryer also has several air blowers cross the machine direction that deliver the hot drying air inside the dryer while also supporting the web.

The integrated gas burners have a thermal power between approximately 0.4-2 MW. They raise the drying air temperature from ambient temperature to 175-200°C, 110-140°C and 80-100°C, in silicone curing, adhesive drying, and primer drying, respectively. The air flow rate inside a dryer is approximately 10 m^3/s, and in most dryers a portion of the air is circulated back to the dryer and only approximately 3 m^3/s of fresh air needs to be heated from ambient temperature to process temperature. In some of the silicone dryers all process air is led to exhaust to avoid the formation of silicone dust. Silicone dust forms when the particles that evaporate and mix into the process air during silicone curing come across temperatures over 380 °C. The burner flame temperatures are far higher resulting in the formation of silicone dust if process air is circulated through the burners and back into the drying oven.

The case study coating machines (CM) in both C1 and C2 have a very similar working principle as was shown in Figures 18 and 19. While similar, CM1 and CM2 have some differences. CM2 is a much bigger coating machine than CM1. It has a much higher manufacturing capacity, and its thermal power is approximately four times the thermal power of CM1. Both machines use water-based adhesives, but CM1 can also use so-called hotmelt adhesives. Hotmelts do not require drying, as they are set with UV-lights.

4.3 Technical ranking of natural gas alternatives

The main objective of this thesis is to map out the possible ways of replacing natural gas in process heat production and providing UPM Raflatac with a preliminary suggestion of the most promising options for decarbonizing the pressure sensitive label manufacturing process. The results of the literary study were taken and limited so that one solution was selected from each of the technology categories presented in Chapter 2 (Table 5).

Table 5. *Description of selected technologies.*

Technology	*Description*
Electrification	Electrification through resistive heating using an electric boiler, heat transfer fluid and heat exchangers on each drying oven
HTHP	High-temperature heat pump specifically designed to deliver hot air to a process
Solar thermal	A parabolic trough collector field with energy storages, heat transfer fluid, and heat exchangers on each drying oven
Green hydrogen	Switching fuels from natural gas to green hydrogen
Synthetic methane	Switching fuels from natural gas to synthetic methane
Biomethane	Switching fuels from natural gas to biomethane
CCS	A post-combustion carbon capture system

Since there are many hypothetically potential options for replacing natural gas, they first needed to be ranked in relation to this specific drying process. The ranking is based on 9 criteria that were selected together with a group of employees at UPM Raflatac who are very familiar with the label manufacturing process and its requirements. Some criteria are more general, while others are more specific to this manufacturing process. Some criteria are also more essential to the manufacturing process than others. Therefore, the criteria were first ranked against each other to determine a weight factor for each criterion (Table 6).

Table 6. *Description and ranking of the selected ranking criteria.*

Criterion	*Weight factor*	*Description of criterion*
Provided temperature	9	Required process temperature, 200 °C
Thermal power	8	Required thermal power for the whole manufacturing line (the combined nominal power of the current gas burners)
Availability	7	Availability of technology
Size/space	6	Space requirement for the new system
Energy cost [€/kWh]	5	Cost for the main source of energy that is used in the system
Thermal efficiency	4	The ratio of thermal output of the system and energy input into the system
System preheat time	3	Amount of time to reach process temperature
Maintenance costs	2	Yearly maintenance costs
Silicone dust formation	1	Silicone dust forms after a certain temperature point, this is not desirable

The most important criterion for the new system is the ability to heat the process air up to process temperature. The manufacturing of pressure sensitive label requires a process temperature up to 200 °C. As described in chapter 4.2 parts of the process require a lower temperature. However, the goal of this thesis is to provide the company with an option for decarbonizing the whole drying process. This includes the parts with the highest temperature requirement, and therefore the technologies are rated on being able to provide a temperature of 200 °C. In addition, the heating system should be able to provide this temperature around the clock and during the whole year to receive the highest ranking.

The thermal power requirement is also one of the key criteria, especially since decarbonization of the whole drying line is the goal. The case studies in this thesis are quite different in this regard, since the thermal power of CM2 is roughly four times the thermal power of CM1.

Availability of technology is key, when exploring decarbonization solutions before 2030. UPM has a target to reduce scope 1 and 2 emissions with 65 % compared to 2015 levels by 2030 (UPM Raflatac, 2024). The time it takes for a company to plan, invest, and carry out an investment project may take years depending on the complexity of the project. Therefore, the technology readiness level (TRL) of the evaluated technologies should be as high as possible, preferably 9. TRL 9 means that the actual system has been proven in an operational environment. (European Commission, 2024) It is not enough that the technology has proof of concept, it needs to already be commercially available for the best chance at achieving the climate targets by 2030.

Fitting a new drying system into an already existing factory that was not built with that new system in mind is a challenge space-wise. Therefore, it is beneficial to rank the options based on their size as well. Space may be available inside the dryer, around the coating machine on the factory floor, or outside the factory on the factory grounds. Different solutions require space from different parts of the factory, and this may affect their ranking.

Energy cost largely determines the cost of operation. Here energy cost describes the cost of the main source of thermal energy in the system. For example, for an electric boiler system the energy cost is the price of electricity and for a burner it is the price of fuel even though the system includes components that are driven with electricity like circulation air fans. Thermal efficiency was also estimated, and in combination with the energy cost, they make up the ranking for each solution’s operation costs.

The drying ovens need to be heated to a certain temperature before production can begin. This takes time, and a lot of energy is used to heat the shells of the drying ovens. Minimizing the drying line’s preheat time is not a priority, but having significantly longer preheat times compared to now is also not desired. An estimate of the potential preheat times were also discussed with a UPM Raflatac employee to get the most accurate ranking with the available information.

The maintenance cost is one of the lower-priority criteria. It was still selected as a criterion because high maintenance costs can ultimately make an investment non-feasible even if the investment costs are moderate. Having to maintain a system more often also takes time away from production hours, which is not desirable. The maintenance costs for each system were evaluated by the maintenance staff at UPM Raflatac, since reliable literary sources were hard to find.

Silicone dust formation is the last criterion that was selected. Silicone dust forms in the silicone dryers where the silicone layer shown in Figure 17 is cured. When certain components of the silicone layer evaporate, get mixed with the drying air, and then get recirculated through the burner, it forms silicone dust that gets stuck on the production line, the area surrounding the drying oven, and for example heat exchanger piping. This is not ideal for the process and results in higher maintenance costs. Silicone dust forms when the temperature is above 380 °C, and it is mainly a problem in burner solutions due to high flame temperatures.

After these criteria were evaluated against each other the technologies in Table 5 were ranked for each criterion on a scale of 0 to 5. 0 meaning that the technology does not meet the needs of the criterion, and 5 meaning that the technology meets the criterion. These rankings were then multiplied with the weight factor for each criterion to give the weighted ranking for each technology (Table 7). The ranking was done separately for both case factories, and the top two highest ranked technologies were then selected for the economic and environmental study.

Table 7. *Results of the technology ranking.*

Technology	*C1*	*C2*
Electrification	4.60	4.18
HTHP	1.98	1.87
Solar thermal	2.29	2.93
Green hydrogen	3.11	3.20
Synthetic methane	3.13	3.22
Biomethane	3.51	3.44
CCS	3.16	3.27

It is evident from Table 7 that electrification and biomethane stood out in both cases even though the ranking was closer in the case of C2. The main reason that electrification stood out in both cases was that the technology is available, and able to produce a high-enough temperature as well as thermal power. Electricity is also cheaper compared to the alternative fuels as shown in Chapter 2 and an electric boiler’s thermal efficiency can be close to 1 (Beyond Zero Emissions, 2018). Electrifying the drying process in this way would also get rid of the silicone dust problem, because temperatures could be kept low-enough on the process side.

In contrast, the main reason for biomethane being the second-best option in both cases is that it would keep the process as it is, and the process as it is works well. The biggest problems with biomethane are availability and the price, but compared to the other options there were less problems.

In terms of the other options, the biggest problems with the other alternative fuels were also availability and price. As described in Chapter 2, neither C1 nor C2 has green hydrogen or synthetic methane production, and the production costs are currently estimated very high. In addition, using green hydrogen presents safety issues that would need to be solved. These alternative fuels also do not solve the issue of silicone dust formation.

Utilizing CCS would not change the current manufacturing process just add to it. However, it was found that the carbon dioxide concentration in the flue gases of the manufacturing facilities is too low for current CCS technologies as they require a CO_2 concentration of at least 1 % in flue gases (many much higher) and the concentration is below that in the case study factories (Global CCS Institute, 2023). The biggest issue with solar thermal technologies is that neither C1 nor C2 is located in an optimal area to use solar thermal technologies, and therefore the amount of space required to deliver enough power to the process would be too high to fit onto the factory grounds. UPM Raflatac processes also need to be able to run around the clock, and therefore energy storages or a parallel heating system would need to be installed, driving up the investment cost. Lastly HTHP technology is not ready yet for lifting air temperature from ambient temperature to 200 °C. The solutions for providing hot air into a process are also quite small, with thermal power ranging from 10 kW to 1 MW. The technology at the moment is best suited to steam generation, waste heat recovery, and lower-temperature applications. (IEA, 2023b)

4.4 Technologies for the future

A similar ranking as in the previous chapter was done for a hypothetical new factory built after 2030 as one of the objectives of this thesis was to map out the most potential technologies for cases beyond 2030. Compared to the ranking in the previous chapter, some changes were made. The criteria of space and availability were left out of the future ranking as a new factory could be designed from the start around a specific heating system, and as the research in Chapter 2 indicates, all these potential heating methods are being developed if they are not already commercial. The criterion of thermal capacity was also left out, because there is no knowledge how much power would be needed in a new factory. Also, all the technologies except for HTHPs can already produce enough thermal power for the whole drying line, although solar thermal systems cannot do that around the clock. With these modifications, the ranking criteria are listed in Table 8 and the results of the future technology ranking in Table 9.

Table 8. *Technology ranking criteria for new-build factories.*

Criterion	*Wight factor*	*Description of criterion*
Temperature	6	Required process temperature, 200 °C
Energy cost	5	Cost for the main source of energy that is used in the system
Thermal efficiency	4	The ratio of thermal output of the system and energy input into the system
System preheat time	3	Amount of time to reach process temperature
Maintenance costs	2	Yearly maintenance costs
Silicone dust	1	Silicone dust forms after a certain temperature point, this is not desirable

Table 9. *Results of the technology ranking beyond 2030.*

Technology	*Weighted ranking*
Electrification	4.52
HTHP	4.52
Solar thermal	3.67
Green hydrogen	3.14
Synthetic methane	2.90
Biomethane	3.38
CCS	3.52

High-temperature heat pumps and solar thermal systems have a much higher ranking in the new-build case compared to the retrofit case. Assuming that after 2030 all technologies have developed resulted in a much higher ranking for HTHP technology since it is perhaps the technology that needs most development to fit the criteria of a pressure sensitive label manufacturing process. Availability, capacity and temperature were the biggest issues, and removing the criteria for capacity and availability makes a significant difference in the ranking. For the future scenario it was also assumed based on literature that HTHPs will have consistently higher temperature lifts after 2030, and therefore the temperature requirement was also ranked higher for this future scenario (IEA, 2023b).

For solar thermal systems space was the lowest ranked criterion for the case studies of this thesis, since they need a substantial amount of land space and space for thermal storage as well. Space would not be an issue if a new factory can be designed around the heating system. Removing the criteria for capacity and availability also slightly raised the weighted ranking of solar thermal as they cannot be ranked highest for solar thermal technologies because of the availability issues with solar radiation. As mentioned, availability is also the biggest issue for CCS technologies (capture technologies for very low concentrations of CO_2) and removing that criterion raised its ranking.

The alternative fuels have the lowest rankings in this future scenario. Using gas burners has the problem of silicone dust formation, which also leads to higher maintenance costs. Their thermal efficiency is also lower compared to methods of electrification (Table 4a and 4b), meanwhile their energy costs are most likely higher also in the future compared to electricity since electricity is needed to produce green hydrogen and green hydrogen is needed to produce renewable synthetic methane. Biomethane could possibly compete with energy prices if production amounts rise, and production efficiency is increased. Predicting energy prices many years into the future, however, is very challenging and matters like subsidies and technological advancements may affect the outcome. Here it was assumed that electricity will be the most affordable source of energy beyond 2030.

4.5 Technical integration

This thesis does not aim to model and dimension a new heating system in detail, but in this chapter a rough idea of how the highest ranked solutions could work at UPM Raflatac factories is given. As previously mentioned in Chapter 2.2.6, switching fuels from natural gas to biomethane would technically be an easy option to decarbonize the drying line. Due to the similar chemical properties of natural gas and biomethane, biomethane could be used without any changes to the current system. In this thesis it is also assumed that the existing natural gas grid could be used to transport the new fuel to the factories. This will have to be confirmed in the face of an actual change in the process. If the gas grid cannot be used for transport, additional transportation costs can emerge.

Electrifying the drying line is technically more complex as it would require a lot of new equipment to be integrated into the existing drying line. The system would consist of an electric boiler, piping, heat exchangers, and auxiliary equipment. The electric boiler serves as the central heating unit. Electric resistors inside the boiler heat up a heat transfer fluid (HTF) (for example thermal oil) that is delivered to the drying ovens via piping. Each dryer would have a liquid-to-air heat exchanger of its own that heats up the process air up to process temperature. A simple sketch of the boiler system is presented in Figure 20.

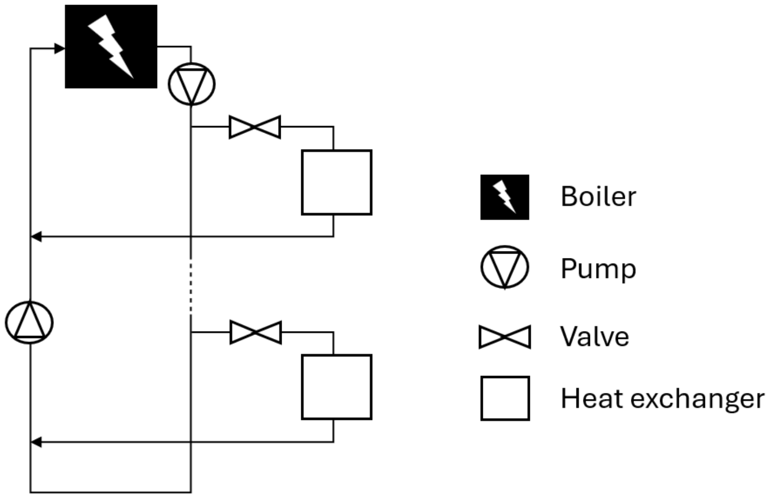

Figure 20. *Simplified layout of the electric boiler drying system.*

A boiler system is already used in another UPM Raflatac location and has been deemed functional. However, retrofitting a new system into the old one can present a challenge as neither of the factories have been built with the new system in mind. The ceiling at the factory in C1 is very low, and the dryers already have integrated gas burners. Both matters make retrofitting the new system more difficult. Additionally, there isn't too much space in the factory for a boiler room. The dryers at the factory in C2 also have integrated burners. Heat exchangers for waste heat recovery and the related piping also take up a lot of space behind the coating machine. There is no realistic way to remove the existing piping and heat exchangers to fit the new drying system, so it would need to be fitted into the drying line despite the limited space.

4.6 Economic study

The economic study contains assessments of investment costs, variable costs (operational costs), fixed costs and revenues for the solutions described in the previous chapter. Investment calculations and a sensitivity analysis are done based on these values. The investment calculations are heavily based on an investment calculation template that is used at UPM Raflatac to assess the feasibility of investments. Using a similar calculation method with only slight changes assures that the results of this economic study can be replicated and compared to similar investment projects that may be assessed at the company in the future.

The initial data used in the economic study is listed in Table 10. For the case of biomethane investment costs were determined as 0, because the new drying system does not require new equipment, only a fuel switch. The same prices of natural gas and electricity as in table 10 were used to determine the change in operation costs. The price for biomethane was set to 90 €/MWh as per Spoof-Tuomi (2021).

The electricity and fuel (natural gas) prices were calculated from Eurostat bi-annual data for non-household consumers from the past 10 years. The 10-year average was selected due to the prices being unstable for the past couple of years and the difficulty in predicting energy prices correctly for a period as long as 20 years. The price of natural gas is expected to stay the same throughout the investment lifetime. UPM Raflatac does not currently partake in emissions trading, and therefore the cost of CO_2 was left out of the calculations.

Table 10. *Initial data for economic study.*

	C1	*C2*	*Unit*
Fuel price	52.09	42.82	€/MWh
Electricity price	70.58	83.37	€/MWh
Investment cost	514 320	1 610 000	€
Maintenance cost	2 → 1	2 → 1	% of investment
Interest rate	7	7	%
Investment lifetime	20	20	a

The operational costs consist of fuel consumption and fuel price as well as, electricity consumption and electricity price in the status quo situation. The fuel consumption is eliminated through electrification of the drying line, and it is assumed that the same amount of energy that was used as fuel will be used as electricity in the new system. The main source of revenue comes from the production of pressure sensitive label and the price of a m^2 of product. However, the production amounts are expected to stay the same after the new system is installed. With these assumptions, the investment's feasibility is heavily dependent on energy prices. The maintenance costs were estimated to be 2 % of the investment cost for the status quo situation dropping down to 1 % after electrification of the drying line. It is also assumed that the heat transfer fluid needs to be replaced every five years increasing the maintenance costs periodically. The operation and maintenance costs and revenues of the new drying line were deducted from the operation and maintenance costs and revenues of status quo to determine the yearly profits/losses of the investment. The yearly investment cost was then deducted from the yearly profits to discover the yearly cash flow resulting from the change.

The investment cost for the electrification of the drying line (Table 11) was estimated based on literary sources as well as data and knowledge available at UPM Raflatac. The most significant parts of the investment cost are the cost of the electric boiler and the heat exchangers. The boiler investment cost is based on values used in studies of Akhtari *et al.* (2020) and Trevisan *et al.* (2022). In the former the capital cost for an electric boiler was estimated to be 54 \$/kW and in the latter the cost for an electric heater was estimated to be 50 €/kW_e. Based on these values 50 €/kW was used to estimate the boiler investment cost.

Since the new drying system has not been more thoroughly designed and dimensioned, it is difficult to estimate an accurate price for the heat exchangers, since the cost may vary significantly based on the type and size of heat exchanger that is needed for the system. Therefore, in this case the cost for the heat exchangers was estimated to be the same as the cost of the electric boiler. The cost of boiler heat transfer fluid, auxiliary equipment, piping and engineering was estimated to be significantly lower than the boiler and heat exchanger investments. The cost for heat transfer fluid, auxiliary equipment, and piping was estimated to be 4 times higher for the C2 factory than the C1 factory based on the size difference of the coating machines in each location.

Table 11. *Breakdown of investment costs.*

	C1	*C2*	*Unit*
Boiler investment	170 000	700 000	€
Heat exchangers	170 000	700 000	€
Heat transfer fluid	20 000	80 000	€
Piping	10 000	40 000	€
Auxiliary equipment	10 000	40 000	€
Engineering	50 000	50 000	€
Connection to grid	84 320	-	€

For the C1 case study, the cost for a grid connection was taken into account. It was calculated with Equation 11.

$$Connection\ charge = a + b * P \tag{11}$$

In the equation a is the direct cost of connection and construction, b is the capacity charge [€/kVA] and P is the contracted capacity. The capacity charge for a medium-voltage connection is 24.8 €/kVA. (Tampereen energia, 2023) The cost of grid connection was only calculated with the capacity charge and the contracted capacity, since the construction costs were unknown. If a new connection to the grid would be needed it is likely that the cost would be higher than what is presented here. For the case study in C2 the grid connection price was left out due to a lack of information.

The investment calculations were done for a period of 20 years. This is the expected investment lifetime. The net present value (NPV) method was used to conduct the calculations, and the interest rate was set to 7 %. The cumulative discounted cashflows as well as the discounted payback time were also calculated for the investment. It was also calculated what the electricity price should be to achieve a payback time of three and ten years.

Finally, a sensitivity analysis was done to determine each variable's impact on the investment's cash flow. Variables selected for the sensitivity analysis are the investment cost, electricity price and natural gas price, maintenance cost, and electricity consumption of the new drying line. These variables were chosen because there might be significant inaccuracies in the assessment of these values, and it is especially difficult to form long-term predictions of energy prices. Demonstrating how these different variables affect the investment's cash flow is valuable information when an investment decision needs to be made.

4.7 Environmental study

The environmental study was done to establish what the environmental benefits of switching to a different fuel or electrifying the drying line would be. UPM Raflatac has goals of reducing their scope 1 and 2 emissions. This thesis specifically focuses on that goal and thus scope 3 emissions were left out of the environmental study. The study is based on different energy consumptions at the case study factories and emission factors for the examined solutions. The emission reductions are calculated as CO_2-equivalent and presented here as a percentage of the emissions of the current drying system.

Scopes 1 and 2 include two sources of emissions. The gas burners on the drying line currently use natural gas as fuel resulting in emissions, and electricity is used in the drying line to drive auxiliary equipment like circulation fans. The production of electricity can cause emissions in scope 2 that need to be taken into account as stated in Chapter 3. The life-cycle emissions for electricity are not considered in this environmental study. Life-cycle emissions would include, for example, the construction of the power plant (GHG Protocol, 2015). The emissions from manufacturing the fossil-free drying options like the electric boiler are also not considered here.

The emission factors used in this study are listed in Table 12. For the case study in C1 there are three values listed for electricity production: one for renewable electricity, one for the national electricity generation (SF, 2022), and one for the residual distribution of electricity (Energiavirasto, 2023b). The two latter values are from 2022. For the C2 case study, only one emission factor was used for the national electricity generation (EEA, 2024), as a similar value to the residual distribution of electricity in C1 was not found.

Table 12. *Emission factors for environmental study.*

Energy source	*C1*	*C2*	*Unit*
Natural gas	201.96	201.96	kg CO_2e/MWh
Biomethane	0	0	kg CO_2e/MWh
Renewable electricity	0	0	kg CO_2e/MWh
National electricity generation	67.5	681	kg CO_2e/MWh
Electricity (residual)	471.27	-	kg CO_2e/MWh

The total annual CO_2-equivalent emissions were calculated using these emission factors and the factory-specific electricity and fuel consumptions. The actual energy consumptions are not listed here to avoid displaying confidential production data from the factories. Based on the cash flows from the economic study and the amount of reduced emissions a price for a tonne of abated CO_2e was also calculated using Equation 10. This was done to demonstrate the cost of emission reductions with the assumptions made in this thesis. The environmental benefit of a new drying system is an important indicator for decision makers when estimating the total benefits of a new drying system.

5. RESULTS

In this chapter the results of the economic and environmental study are presented and analyzed. Results of the sensitivity analysis are also discussed. Finally, the impact of this research is evaluated and suggestions for further research are given.

5.1 Economic study

In the case of biomethane the new drying system's profitability comes down to the prices of natural gas and biomethane, since investment costs were assumed to be 0. Using the 10-year average prices for natural gas and electricity while the price for biomethane was set to 90 €/MWh resulted in operation costs rising and therefore the yearly discounted cash flow being negative. The cumulative discounted cash flow is presented in Figure 21 for both CM1 and CM2.

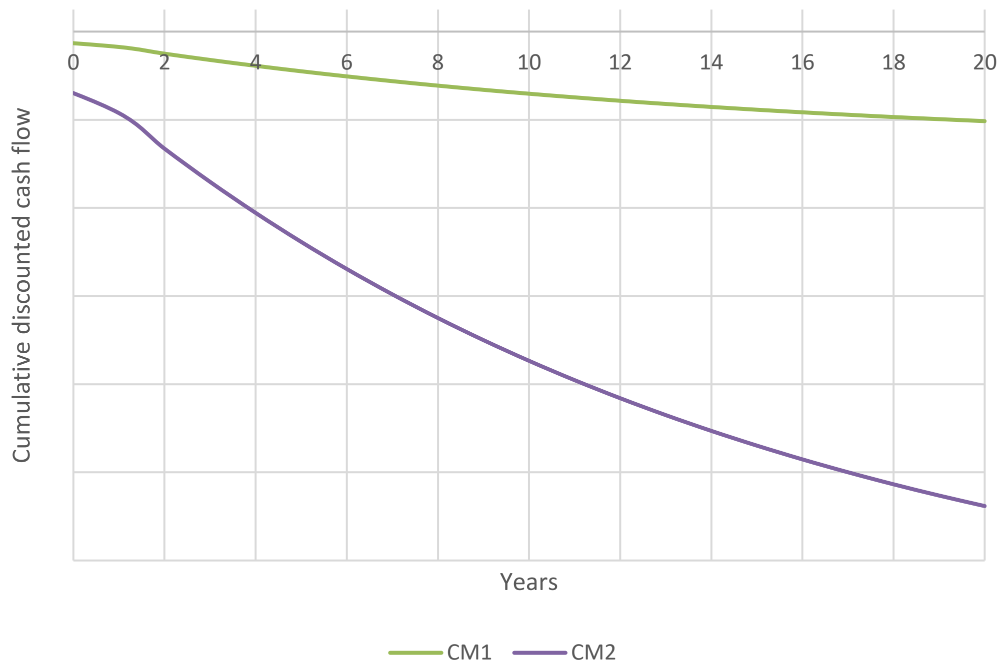

Figure 21. *Cumulative discounted cash flow for the biomethane case study in C1 and C2.*

The results in Figure 21 were predictable, since the used price for biomethane 90€/MWh is higher than the 10-year average price for natural gas in C1 and C2. If a switch to a more expensive fuel is made, and it does not affect anything else in the process, the operation costs will rise. The cumulative discounted cash flow for CM2 is much lower than for CM1 since CM2 is a larger coating machine that uses a bigger amount of fuel.

The premise for the economic study for electrification was presented in Table 10. The assumption was that the energy consumption of the drying line would stay the same regardless of the new system. The amount of manufactured product and therefore revenue was also assumed to stay the same. With these assumptions the feasibility of the investment is heavily dependent on the prices on natural gas and electricity as can be seen from the results (Table 13).

Table 13. *Results of the economic study for electrification.*

	C1	*C2*	*Unit*
NPV	-1.3	-9.3	M€
Payback time	-	-	a
Profit	-79,826	-777,072	€/a
Profit when HTF is changed	-99,826	-857,072	€/a

The investment is not feasible with the assumptions that have been made. Natural gas has been relatively cheap in both C1 and C2 for the past ten years. Changing to more expensive electricity results in higher operation costs that inevitably turn the yearly cash flows negative making it impossible for the investment to have a payback time or a positive NPV. The cumulative discounted cashflows in the case of electrification resemble the cumulative discounted cash flows in the case of switching to biomethane (Figure 22).

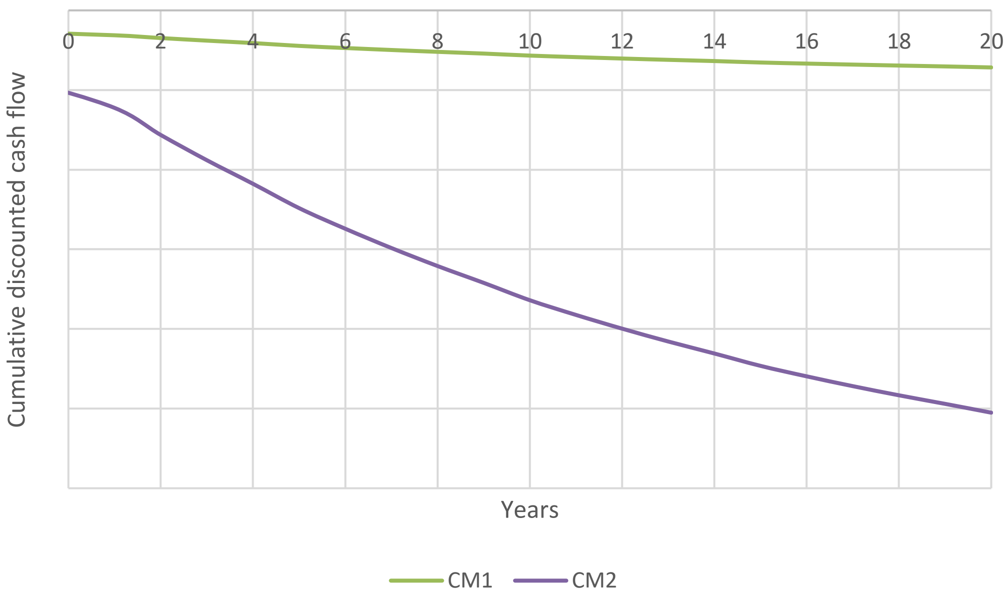

Figure 22. *Cumulative discounted cash flow for the electrification case study.*

The energy consumption of CM2 is significantly higher than the energy consumption of CM1. The result can be seen in Figure 22 as the cumulative discounted cashflow for CM2 dips far lower than the cash flow for CM1. This can also be seen in the previous table where the NPV for both cases was presented. The NPV for the C2 case study is roughly seven times lower than the NPV for C1 case study. According to the NPV method the investment on the C2 factory is even worse than the investment on C1 factory since it results in bigger losses.

With the initial values and assumptions made in these calculations, the investment has no payback time. To get a payback time and a positive net present value (NPV) for the investment, the price of electricity would need to be significantly lower. In Table 14 the price of electricity needed to achieve a 3- and 10-year payback time has been calculated. The NPV in these cases is also listed below.

Table 14. *Electricity prices and net present values for 3-year and 10-year payback time.*

	C1	*C2*	*Unit*
Electricity price 3-year payback	7.55	10.08	€/MWh
Electricity price 10-year payback	35.39	30.39	€/MWh
NPV 3-year payback	1,561,568	4,858,403	€
NPV 10-year payback	295,126	923,788	€

With the assumptions made before, the price of electricity needs to be very optimistically low for the investment to have a payback time. For a 3-year payback time in both cases electricity would have to cost around 10 €/MWh or under, and even for the 10-year payback time electricity would have to cost around 35 €/MWh in C1 and 30 €/MWh in C2. Given that the 10-year average price of electricity for non-household consumers has been 70.58 €/MWh in C1 and 83.37 €/MWh in C2 (Eurostat, 2024a) it is safe to say that it is unlikely that electricity prices will drop low-enough to make the investment feasible on its own. For the investment to be feasible other factors also need to change. A more detailed analysis of this is presented in the next chapter.

5.2 Sensitivity analysis

Due to the lack of designing and dimensioning the new electricity-based drying system, many rough assumptions had to be made in order to carry out the investment calculations. It is very important to evaluate the impact that these different assumptions may have on the results. Therefore, a sensitivity analysis was done by choosing five variables and changing them one at a time and recording their impact on the investment cash flow. Comparing the variables to investment cash flow was selected because with the initial values and assumptions the investment does not have a payback time making it difficult to examine the variables’ impact on that.

The five variables that were examined in this sensitivity analysis are investment cost, electricity price, natural gas price, total electricity consumption and maintenance costs. These variables were chosen because there is uncertainty in the accuracy of their initial values. In Figure 23 the impact of these variables on the C1 investment cash flow is illustrated. The impact is presented as a percentual change when the variables change -40 % - 40 %.

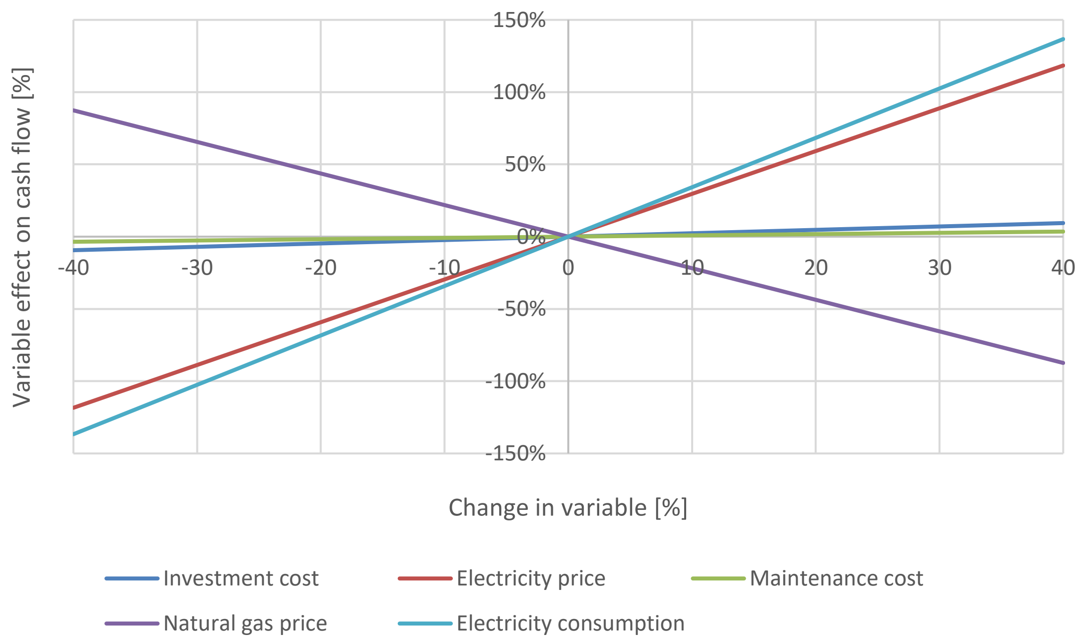

Figure 23. *Sensitivity analysis for the electrification investment in C1 presented as variables’ effect on investment cash flow.*

Electricity consumption has the highest impact on the cash flow. It has an ability to decrease or increase the cashflow by 137 % with a 40 % increase or decrease in the consumption. This means that if the new system used 40 % less energy than the current system, the cash flow would turn positive making it possible for the investment to have a payback time. This shows that the assumption of energy consumption staying the same is a very significant assumption, and for more accurate investment calculations it is important to establish how energy consumption differs between the two drying systems.

Electricity price has a similar impact on the cash flow, increasing or decreasing it by a maximum of 118 %. Electricity price, however, is a variable that is not dependent on the design of the process itself. It changes with the energy markets and is hard to predict. When making investment decisions it would be smart to design the system first to establish the other variables, and then calculate a threshold for electricity price where the investment is profitable. If the company can acquire an electricity contract with a provider that falls under this threshold the investment will be profitable.

Natural gas has a reverse impact on the cash flow than the previous two. If the price of natural gas increases the negative cash flow decreases. The impact is not as big as the impact of electricity price or consumption because the consumption of natural gas in status quo is smaller than the consumption of electricity in the new system. However, the impact natural gas has on the cash flow is still significant and needs to be taken into consideration. The possibility of, for example, emissions trading can affect the cost-effectiveness of using natural gas.

The initial investment cost and yearly maintenance costs have little impact on the cash flow. Although the investment cost can be high it only takes place once and is quite insignificant compared to the operational costs of the drying process. Yearly maintenance costs are also very low compared to the energy costs, and their impact on the cash flow is ultimately very limited. It needs to be noted, however, that this sensitivity analysis focused specifically on the impact on investment cash flow. If the investment was feasible to begin with, the investment cost could have a significant impact on the investment payback time.

Similar results were gotten in the sensitivity analysis for C2 as for C1. The results are presented in Figure 24.

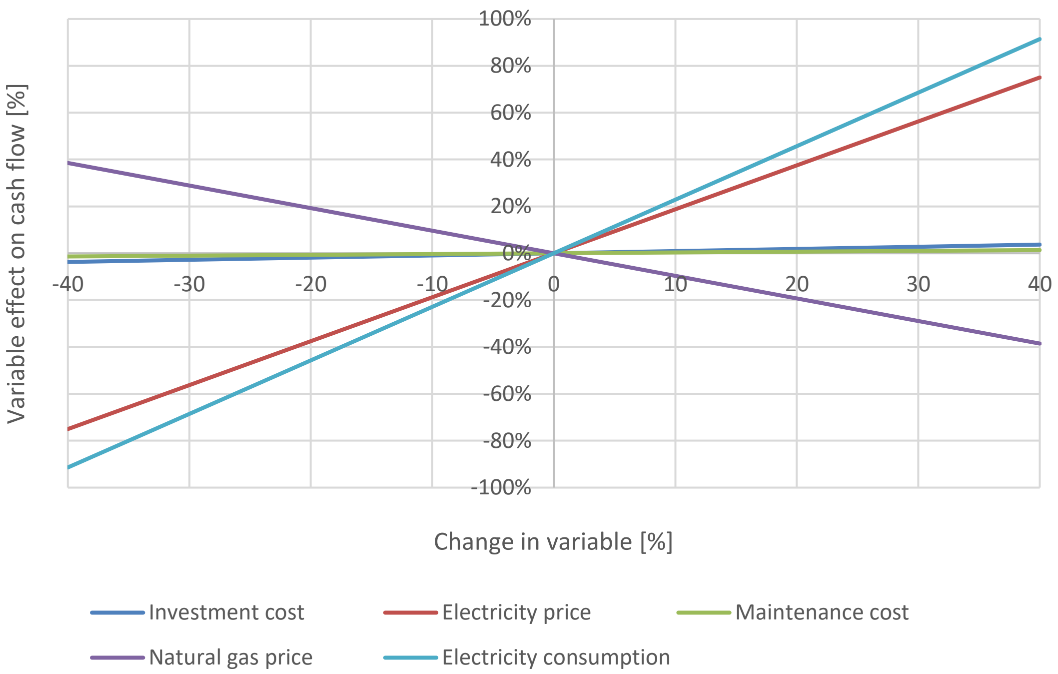

Figure 24. *Sensitivity analysis for the electrification investment in C2 presented as variables' effect on investment cash flow.*

The results are very similar to the results of the C1 sensitivity analysis. Electricity consumption has the highest impact while investment cost and maintenance costs have the lowest impact. What is notable between these two case studies is that none of the variables are able to change the cash flow over 100 % in the C2 sensitivity analysis. For example, having a 40 % decrease in the total electricity consumption resulted in a 91.4 % increase in cash flow, but it was still not enough to turn the cash flow positive and enable a payback time. Other changes are needed as well for that to happen. The price of natural gas and electricity are so far apart in C2 that even a significant drop in electricity prices or consumption is not enough to turn the cash flow positive on its own.

5.3 Environmental study

As of now, both case study factories utilize electricity with an emission factor of 0. Therefore, the combustion of natural gas is the only source of GHG emissions from the drying line. With the base assumption of energy consumption of the drying process staying the same, the emission reductions are directly related to the emission factors of natural gas, and additional electricity. In Figure 25, emissions for the C1 case study with electricity emission factors from Table 12 are presented.

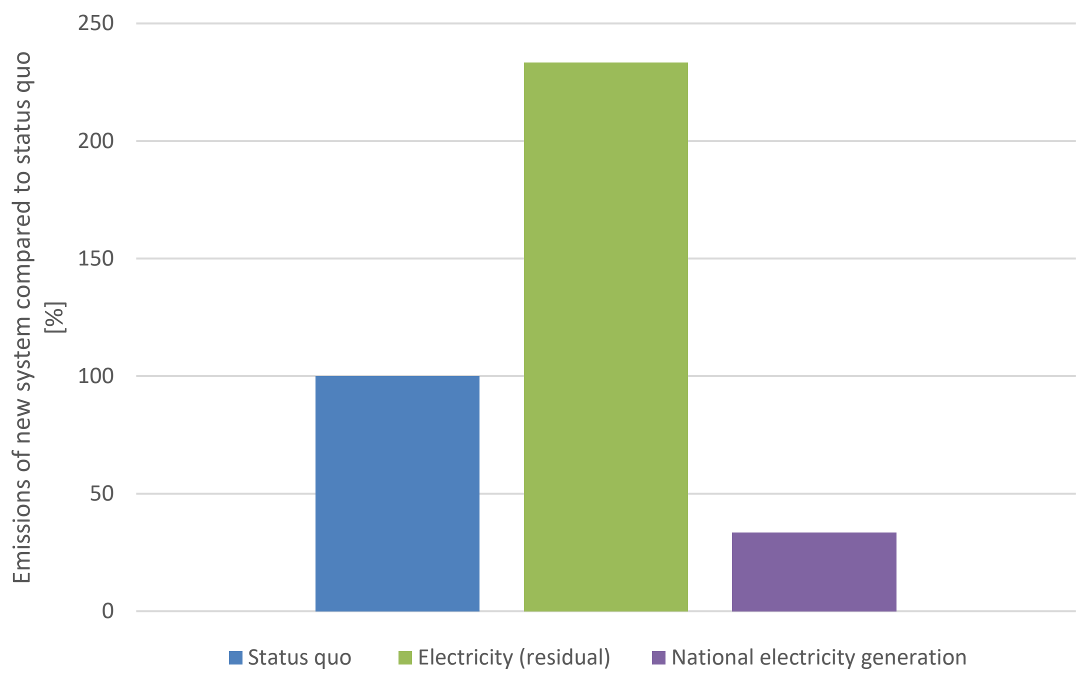

Figure 25. *Drying line emissions from CM1 with different electricity emission factors.*

From this figure the importance of the source of electricity is apparent. Natural gas is a fossil fuel, but it has a relatively low emission factor (201.96) compared to other fossil fuels. For example, coal has an emission factor of 403.2 and diesel oil's emission factor is 266.76. (IPCC, 2023, according to Our World in Data 2023) If electricity for the new drying system is produced using mainly fossil fuels (residual electricity) the emissions of the drying process can be higher than when using natural gas. If electricity from renewable sources is available or at least the emission factor for national electricity generation can be used for the additional electricity, a reduction in emissions can be seen. Figure 25 does not illustrate the cases for renewable electricity and biomethane since they have an emission factor of 0 resulting in a 100 % reduction in emissions from the drying process.

Figures 26 and 27 present how the emission reductions change if the new drying process would consume more or less energy than the current system in C1. In Figure 26 the emission factor for national electricity production was used while in Figure 27 the emission factor for residual electricity was used. The central column in the figures represent the situation in Figure 25, where energy consumption of the new system stays the same as the current energy consumption.

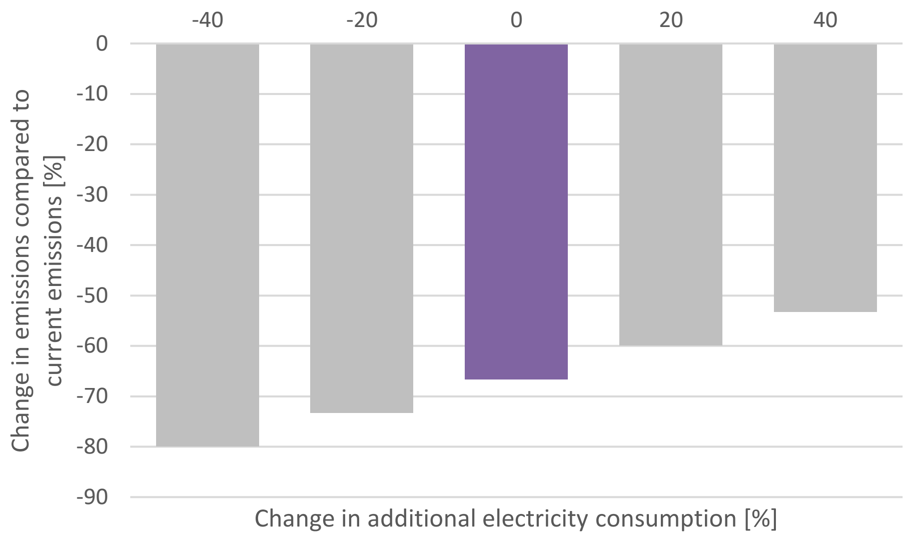

Figure 26. *Emission reductions of CM1 with different electricity consumptions.*

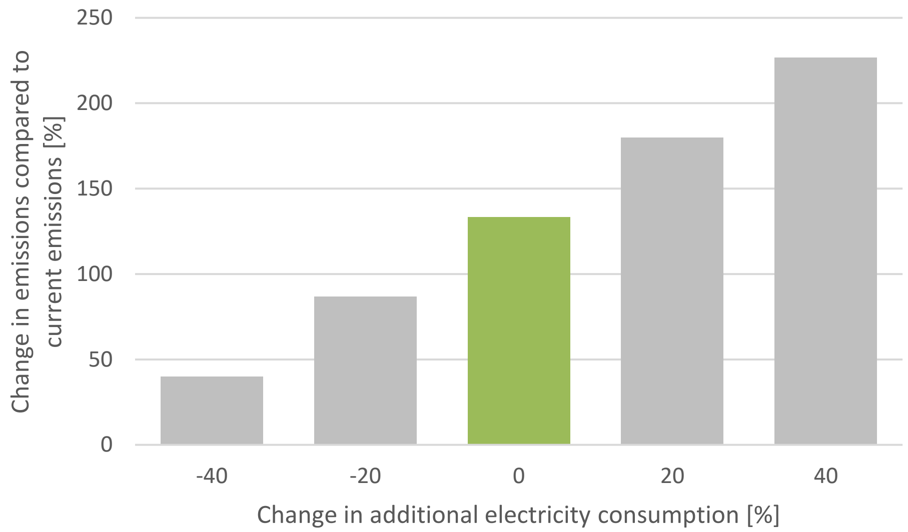

Figure 27. *Emission reductions of CM1 with different electricity consumptions.*

These figures further demonstrate how important the source of electricity is for the emission reductions of the new system. As can be seen from Figure 27, if electricity from renewable sources cannot be provided for the new drying process and electricity with a high emission factor needs to be used, even with a 40 % decrease in the drying process energy consumption the emissions still increase. In contrast, if a contract for electricity with a lower emission factor can be made, emissions are reduced by 66.5 % even with the conservative assumption of the system's energy consumption staying the same (Figure 26).

In C2, around 70 % of electricity is generated by burning coal, and the emission factor for national electricity production is therefore very high (IEA, 2024b). Because of this, in the case of the C2 it is essential that renewable electricity can be used if the drying line is electrified. In Figure 28 the emissions of the current and new system are shown, and in Figure 29 the emissions reductions with different electricity consumptions are demonstrated. Once again, renewable electricity and biomethane have been left out of the graphs since their emission factor is 0 and they have the potential to reduce GHG emissions by 100 %.

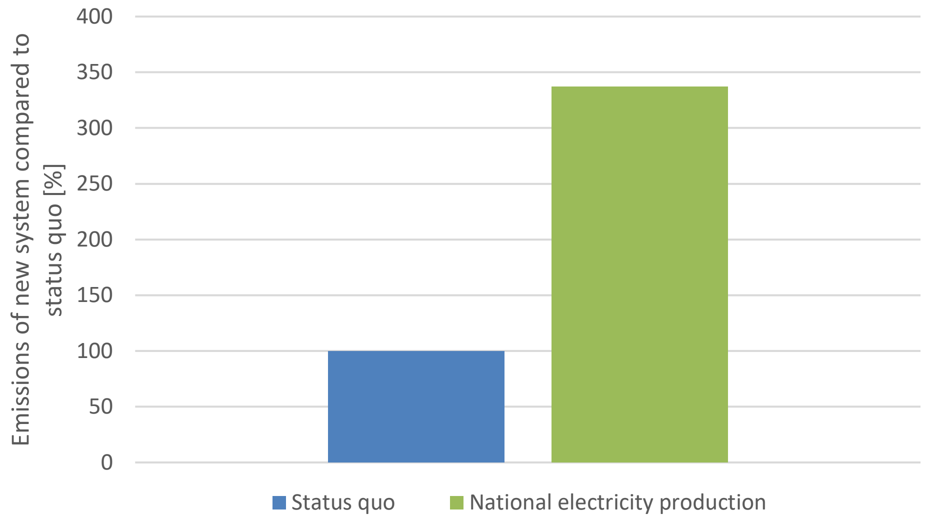

Figure 28. *Drying line emissions from CM2.*

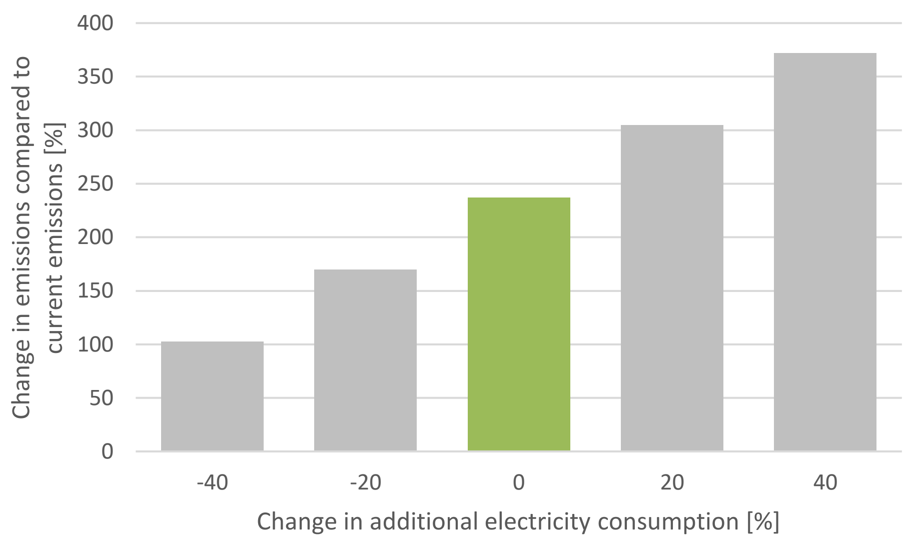

Figure 29. *Emission reductions of CM2 with different electricity consumptions.*

As predicted, emissions of the drying process actually increase in C2 if renewable electricity is not available for the electrification and the emission factor for national electricity production has to be used. Even if the electricity consumption would drop by 40 % due to the new system the emissions would still increase by just over 100 %. The motivation to decarbonize the drying process for UPM Raflatac is to be able to reach the goal of 65 % emission reductions in their own manufacturing processes. If electrification is selected as the method to reach this goal, it is essential that an electricity contract with low-enough emission factor electricity (preferably renewable electricity) can be secured.

With combining the economic and environmental study, a levelized cost of carbon abatement (LCCA) was calculated with Equation 10 for cases where emissions were reduced. This includes the electrification with renewable electricity and switching to biomethane in both C1 and C2, and in C1's case electrification using the emission factor for national electricity generation. The resulting LCCAs are presented in Table 15.

Table 15. *Levelized cost of carbon abatement for electrification with low emission factor electricity and use of biomethane.*

Case	*Price*	*Unit*
C1 (biomethane)	197.12	€/tCO_2e
C2 (biomethane)	245.29	€/tCO_2e
C1 (renewable)	118.06	€/tCO_2e
C1 (national electricity generation)	177.33	€/tCO_2e
C2 (renewable)	221.11	€/tCO_2e

The lowest price for LCCA was achieved in the C1 case where renewable electricity was used for electrification. Even when using renewable electricity, the LCCA in the C2 case ended up being over 100 €/tCO_2e higher than in C1. The difference in the price of natural gas and electricity is higher in C2 than in C1 causing the difference in operational costs to be higher as well in the case of C2. Due to this, the LCCA was significantly higher in the C2 case study. The values for LCCA when switching to biomethane were even higher than for electrification. The high cost used for biomethane is the reason behind this.

All the received values for LCCA are quite high, especially for the C2 case study but also for the C1 case where the emission factor by local authorities was used. Notable is that all the values are higher than what the price for carbon dioxide has been in emissions trading in the past years, as average carbon prices have stayed under 100 €/tCO_2 (Energiavirasto, 2023c). In addition to the investment not being feasible, the price for carbon abatement is also relatively high.

Comparing the amount of reduced GHG emissions to the whole factory's emissions gives a good idea of the impact decarbonizing the drying process has. First, in the case of biomethane and electrification with electricity from renewable sources (emission factor 0) emissions could be reduced by around 18.8 % in the factory in C1. For C2, decarbonizing CM2 could result in emissions reductions of 47.1 % compared to the whole factory's emissions. In C1, when using the emissions factor for national electricity generation, the emission reduction potential is approximately 12.5 % of the factory's emissions.

5.4 Impact and need for further research

The results of this thesis can be used as preliminary groundwork for investment decisions related to the decarbonization of pressure sensitive label manufacturing. The technology ranking can be used as a reference, when different options are explored. However, all manufacturing facilities are different, and assessments need to be made individually for each facility.

The economic and environmental studies give good indications of what the key factors in terms of the investment's feasibility are. The calculations themselves, however, are merely approximate. Since a more in-depth technical analysis or modelling was not the goal of this thesis and therefore not done, the results of the investment calculations cannot be used as they are. When deciding on an investment, more accurate models of the new drying line need to be made since this will make the calculations more accurate. Especially the energy consumption of the new drying system needs to be clarified, investment costs need to be mapped out more accurately, and realistic electricity contracts need to be procured from a supplier. With these clarifications, the investment calculations will already give more accurate results compared to the approximate results of this study.

The results do, however, give some idea of the emission reductions that are possible when decarbonizing a drying line. In the C1 factory almost 20 % emission reductions were achieved when compared to the whole factory's emissions, and in C2 a reduction of almost 50 % was calculated. These reductions alone are not enough to reach UPM Raflatac's emission reduction goals of 65 % of scope 1 and 2 emissions. That will require decarbonizing multiple coating machines in one factory. However, the results indicate that successfully decarbonizing coating machines is an essential step in reducing direct emissions from UPM Raflatac's own factories.

This thesis specifically focused on solutions for decarbonization that could work on their own. What were not touched upon were different hybrid systems. This is a big consideration for future research. It is very well possible that the most optimal way of decarbonization is a combination of different systems. For example, an electric boiler system could be used together with a solar thermal system, or a high-temperature heat pump for waste heat recovery. A boiler system could also be used together with an alternative fuel. A hybrid system could be especially beneficial for optimizing the operational costs. Simply, the system would be operated with the energy source that is more affordable at that time. The investment costs and space requirements for a hybrid system are higher than with a singular decarbonization system. However, seeing that the operational costs heavily determine the profitability of the new drying system, it would be sensible to examine hybrid systems more in-depth.

6. DISCUSSION

Results of the technology ranking were quite expected, and it also demonstrated that the development in the next five to ten years will have a significant impact on what decarbonization technologies will become most utilized in the industry sector. Electrification of pressure sensitive label manufacturing currently seems the most promising option, mainly because some electrification technologies are already commercial and there is a rise in renewable energy. The problem with all the other technologies, with the exception of solar thermal technologies, that were examined was that they are currently not available. Either the technology itself is still developing, or the technology is there but there is still no widespread use of the it due to other matters such as high cost. In terms of solar thermal technologies, countries 1 and 2 are not located in optimal regions.

The economic and environmental studies also gave quite predictable results. Switching to biomethane is not economically feasible while biomethane is more expensive than natural gas, and the investment in electrification is not feasible with the base assumptions presented in chapter 4.6. The most significant matter for the investment's feasibility is the cost of natural gas and electricity that directly affect the operation costs. With the average prices from the past 10 years the investment cash flows stayed negative for both C1 and C2. With negative cash flows it is impossible to have a payback time for the investment, and in that situation the size of the investment cost hardly matters.

There is a lot of uncertainty related to the investment costs in this thesis: the heat exchanger investment is only a guess since no knowledge of the specific type of heat exchanger was available for this thesis, the engineering, and piping and auxiliary equipment costs were estimations based on prior knowledge and UPM Raflatac documentation, and some possible costs such as the building of a boiler room were completely left out due to lack of knowledge. These uncertainties need to be addressed once electricity contracts, energy consumption of the new system, and production capacities have been confirmed, since the investment cost does have an impact on the payback time if the cash flows are positive.

Energy consumption of the new system is also a big source of uncertainty in the investment calculations. Since no further modelling of the new drying system was made, it was assumed that the energy consumption would stay the same after electrification. With this assumption to achieve a 3-year payback time the electricity prices needed to be 7.55 €/MWh in C1 and 10.08 €/MWh for C2, which are very low prices. However, even with a

10 % decrease in the total energy consumption the prices for electricity would have to be 8.53 €/MWh for C1 and 11.46 €/MWh for C2 to achieve a 3-year payback time. A 10 % decrease in total energy consumption of a system is quite significant while a 13 % and 13.7 % increase in electricity prices in C1 and C2, respectively, is in terms of percents significant but still leaves the electricity prices at a very optimistically low level.

Electrifying the drying line with stock exchange electricity comes with a risk of very high operation costs as electricity prices fluctuate. A risk assessment of a stock exchange electricity contract and a fixed electricity contract should be made considering the characteristics of the pressure sensitive label manufacturing process. The process is meant to be able to run around the clock, and driving down production when electricity prices rise is not optimal. Therefore, a fixed electricity contract might be a better option if there is no alternative method of heating up the drying line.

Given the above, it seems that for electrification to be feasible, at least three things need to happen in the future. Natural gas needs to become more expensive while the price of electricity from renewables needs to come down, the energy consumption of the drying process needs to lower after electrification, and the investment costs need to be accurately assessed and preferably come down due to factors like technological development. One thing that could also affect the feasibility is the increase in production volumes due to, for example, quicker drying line preheating times and shorter maintenance periods. Increased production would come with increased profits. However, production increases are hard to predict at this point, and therefore production was assumed the same in this thesis.

Electrification is an option for decarbonization, but electrification through an electric boiler has been deemed non-profitable in other studies as well. In his master's thesis Loiva (2024) examined a low-temperature wet rendering plant where different methods of electrification were investigated for waste heat recovery. The three steam generating heat pumps that were investigated were all deemed economically feasible while the fourth option of an electric boiler had such high operation costs that cash flows remained negative, and the investment had no payback time. Similarly, Hasanbeigi & Zuberi (2022) investigated the electrification of thermal oil boilers in the textile industry in China, Japan, and Taiwan. While they concluded that emission reductions could be possible around 2050, the energy costs were estimated to be higher for electric boilers than combustion boilers even in 2050. The electric boilers were shown to result in 13 % energy savings, but it was not enough to offset the high electricity prices of these three countries. These results tell that electrification of an industrial process needs to be carefully examined before making an investment.

Biomethane is technically a good solution for decarbonizing the pressure sensitive label manufacturing process since it does not require investments into new production equipment. But as stated before, biomethane also has its problems, the biggest being that biomethane is not produced at all in C2 and the production in C1 is very limited and directed towards transportation sector. The availability can increase in the coming years if the production of bioproducts is increased to adhere to climate goals. Biomethane is also still estimated to be quite expensive at 90 €/MWh, and since gas prices have come down since the energy crisis, switching fuels would not necessarily be profitable even if biomethane was available for industrial use. In this thesis it was also assumed, that should biomethane be available, it could be transported using the existing gas grid. This would have to be confirmed with the grid operator. If transportation through the grid is not possible, additional transportation costs may appear.

7. CONCLUSIONS

The objective of this thesis was to produce a comprehensive review of technologies that can possibly replace natural gas in process heat production in a pressure sensitive label manufacturing process. A literature study was done to research what decarbonization methods are already used in different industries, and what solutions are perhaps predicted to rise in popularity in the future. Three distinct categories were discernible from the research: decarbonization through electrification of some kind, decarbonization through alternative fuels, and other technologies including solar heating systems and carbon capture and storage.

With such a wide range of technologies it needed to be determined which technologies would be most usable in the specific process of pressure sensitive label manufacturing. A group of criteria were selected together with the engineers at UPM Raflatac. These criteria were used to rank all the possible solutions that were discovered during the literature review. From the ranking it was concluded that electrifying the drying system with resistive heating or replacing natural gas with biomethane, a chemically similar but environmentally better fuel than natural gas, were the best options to achieve the climate goals that UPM Raflatac has set for itself. A similar technology ranking beyond 2030 suggested that electrification (including HTHPs) will be the best solution for decarbonizing the pressure sensitive label manufacturing process after 2030.

Decarbonizing the current manufacturing processes via electrification or biomethane was further explored in an economic and environmental study. It was concluded that with the base values and assumptions that were made, investing in electrification is not feasible and the investment does not have a payback time. To have a payback time of three years the electricity price would have to be 7.55 €/MWh for C1 and 10.08 €/MWh for C2. When considering the history of non-household electricity prices in C1 and C2, it is safe to say that average electricity prices will not drop that low. Even for a 10-year payback time the electricity prices needed to be very optimistically low at 35.39 €/MWh and 30.39 €/MWh for C1 and C2, respectively. Two possible reasons for this outcome can be concluded: either the base values and assumptions made for the economic study were too conservative, or electrifying the drying line is not economically feasible with current energy prices, even if less conservative base values were used. Regarding the use of biomethane, feasibility is directly related to the prices of natural gas and biomethane, since no investment costs were assumed for this case. Replacing natural gas with biomethane was also deemed not feasible when the price for biomethane was set to 90 €/MWh. Even if biomethane was cheaper than natural gas, there is not enough biomethane production in C1 and C2 to decarbonize the label manufacturing process this way.

Emission reductions, however, were achievable for both electrification and biomethane. Emissions of the drying line could be reduced to 0 if electricity from renewable sources or biomethane were used. When using electricity from renewable sources the levelized cost of carbon abatement was 118.06 €/tCO_2e and 221.11 €/tCO_2e for C1 and C2, respectively. LCCA was also calculated for CM1 using an emission factor for national electricity generation provided by local authorities. With this emission factor LCCA was 177.33 €/tCO_2e. Notable is that all these values are higher than the price of carbon in emissions trading for the past two years, that has stayed below 100 €/tCO_2e. These results indicate that electrification is an expensive way to decarbonize even when related to the reduced emissions.

Calculating the LCCA for the case of biomethane did not result in any lower values. Since a price of 90 €/MWh for biomethane was used the LCCA rose even higher and was 197.12 €/MWh for C1 and 245.29 €/MWh for C2. Electricity prices in C1 and C2 are lower than 90 €/MWh and therefore LCCA was higher for biomethane even though the biomethane case study did not involve investment costs in this thesis.

Ultimately, these decarbonization options of electrification and biomethane could decrease the manufacturing facility's emissions by 18.8 % at most in C1. This reduction would be possible with an emission factor of 0. Using an emission factor for national electricity generation would only result in reductions of 12.5 %. The coating machine in C2 is much larger than in C1 and decarbonizing that could reduce emissions as much as 47.1 %, when the emission factor is 0. If the highest emission factors for electricity are used for C1 and C2 the total factory emissions rise in both cases highlighting the importance of using low-emission electricity.

This study suggests that there are still few technologies that are optimal for decarbonizing an already existing pressure sensitive label manufacturing process. All cases are, of course, different but in the case of CM1 and CM2 the problems were quite similar. Neither of the factories were built to accommodate a new heating system, and thus installation space is very limited. There are only few commercial technologies that are available and could technically work. Additionally, electrification, which seems to be one of the more potential solutions, is expensive due to the investment costs but especially the operation costs with current electricity prices. The development in energy markets will have an impact on the way industry is decarbonized in the future.

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