

ELECTROLYSIS AND ELECTRO-FUELS IN THE SWEDISH CHEMICAL AND BIO- FUEL INDUSTRY: A COMPARISON OF COSTS AND CLIMATE BENEFITS

Report from an f3 project

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PREFACE

This report is the result of a collaborative project within the Swedish Knowledge Centre for Renewable Transportation Fuels (f3). f3 is a networking organization, which focuses on development of environmentally, economically and socially sustainable renewable fuels, and

- Provides a broad, scientifically based and trustworthy source of knowledge for industry, governments and public authorities,
- Carries through system oriented research related to the entire renewable fuels value chain,
- Acts as national platform stimulating interaction nationally and internationally.

f3 partners include Sweden's most active universities and research institutes within the field, as well as a broad range of industry companies with high relevance. f3 has no political agenda and does not conduct lobbying activities for specific fuels or systems, nor for the f3 partners' respective areas of interest.

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SUMMARY

To reach the national goals of a fossil-independent vehicle fleet by 2030, a 100 % renewable power production by 2040 and a climate neutral society by 2045, it is essential that the production of renewable fuels, the de-fossilisation of Swedish industry at large scale and the development of a more flexible electrical system including large-scale storage now gain momentum. One way that could contribute partly to an electrical system in balance, partly to an increased production of renewable substances, is to utilise the increasing access of renewable, low cost electricity for electrolysing water into hydrogen (herein referred to electro-hydrogen) and oxygen.

Renewable electro-hydrogen can be used as energy storage or as fuel in for example fuel cell vehicles, but may have its outmost potential in processes that replace fossil feedstock and / or energy carriers in various industrial processes such as, for example, steel, chemical and biofuel production. Furthermore, the electro-hydrogen can be used to bind larger CO₂ emissions from e.g. biogas plants, steel or cement industry and via so-called electro-fuel processes (sometimes also called power-to-gas or power-to-fuel) generate valuable products such as methane and methanol in a circular economy. The different applications have different degrees of maturity, but are generally still far from a broad commercial penetration. However, macro-factors, such as falling electricity prices and increasing interest in carbon-neutral products and industrial processes, have initiated a number of major initiatives in this area, e.g. the co-operation between Preem and Vattenfall aimed for the production of 3 Mm³ biofuel by 2030, and HYBRIT aimed to de-fossilise the Swedish steel industry by 2045 via renewable electro-hydrogen.

The aim of this project has been to provide a public, easily accessible summary of the conditions required for electro-hydrogen to be considered as a viable alternative for de-fossilising various industrial sectors in Sweden. As far as we know, although several larger on-going projects in the field, no such besides this one exists today. The analysis is based on a number of case-studies focused on the Swedish chemical and biofuel industry having the Swedish cement and steel industry as references for comparison of the demand for electro-hydrogen. More specifically, the analysis takes off from the following study cases:

1. The electro-hydrogen demand for Preem's biofuel production of 3 Mm³ by 2030
2. The electro-methanol demand for the Swedish RME-production as of today
3. The electro-methanol demand for Perstorp's chemical production in Sweden as of today
4. The electro-hydrogen demand for replacing the blast furnace processes with Hydrogen DRI (Direct Reduction Iron) production in the Swedish steel industry. Reference case 1.
5. A thought scenario of electro-methanol production by capturing and combining the CO₂ emitted from the Swedish cement industry with electro-hydrogen. Reference case 2.

Quantitative cost and climate estimations were enabled by using a calculation model developed at the division of Physical Resource Theory, department of Space, Earth, and Environment, Chalmers University of Technology, using input from industrial stakeholders and the open literature. Main insights from this study can be summarised as:

- Producing hydrogen using electrolyzers, as well as methanol from the hydrogen, are currently expensive processes, but since they can be produced without CO₂ emissions the market value may be double that of fossil hydrogen/methanol leading to possible business opportunities (Figures S1–S2). In a potential future situation where the electro-fuel technology is more mature and there is a market for excess oxygen and heat, we find circumstances when the electro-fuels can have a lower production cost compared to what industries currently buy natural gas based hydrogen/methanol.
- Using electro-fuels for the purpose of de-fossilise parts of the Swedish chemical and biofuel industry as well as parts of the Swedish steel and cement industry demands a large amount of electrolysis capacity and use of fossil free electricity. This would in turn put pressure on existing electricity grid. These electricity issues constitute a challenge for the electro-fuel concept.
- Reducing CO₂ emissions from substituting fossil fuels and feedstock with electro-fuels has a high cost per ton avoided CO₂, however far below the penalty cost from the coming reduction duty policy. The cost may therefore be judged reasonable, from the biofuel industry's perspective, if there is a lack of cheaper renewable options.
- From economic theory it is known that prices will rise if the demand for a product is higher than the supply potential which is something to bear in mind if there in future will be a lack of biofuels (which is a limited resource). In the future, a situation may arise where biofuels are more expensive, potentially leading to that the reduction duty policy first and foremost being fulfilled with options that are less expensive than biofuels. This is where electro-fuels may be cost-compatible.

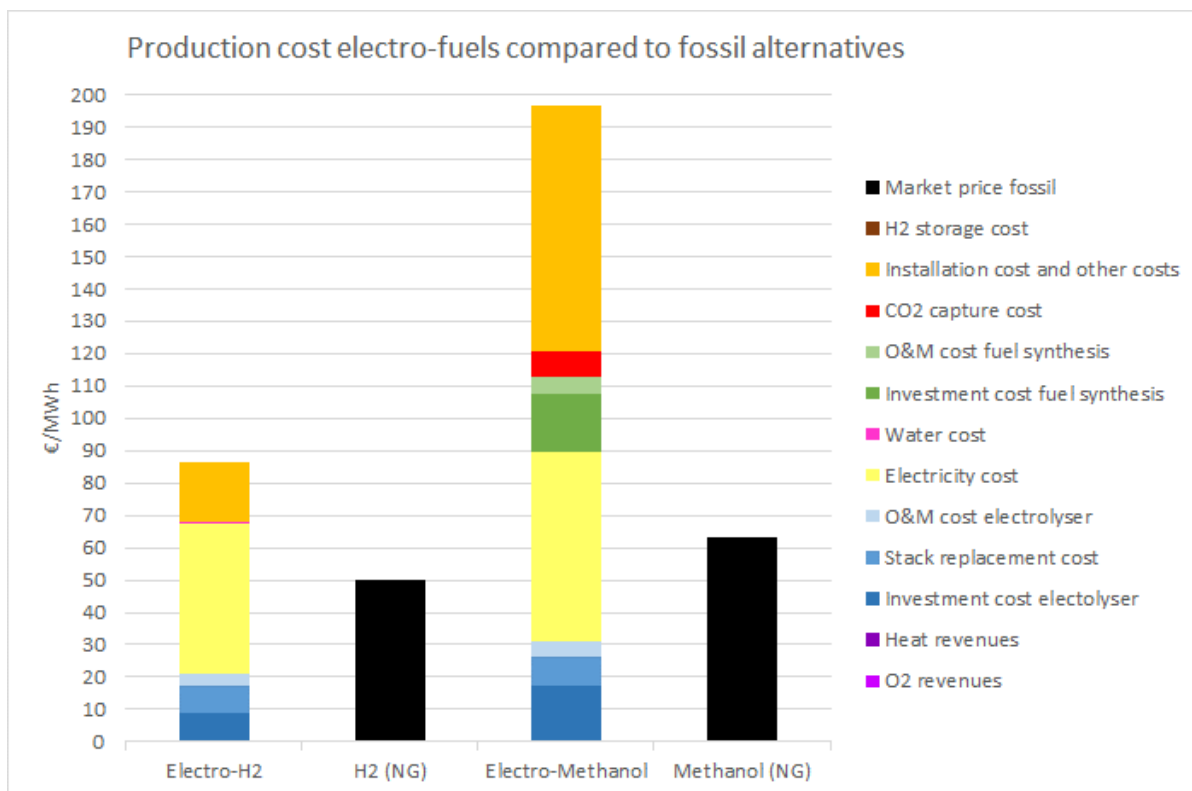


Figure S1. Production cost for electro-fuels, using base case assumptions (Table 7 in the report) and a system lifetime of 25 years for the electro-hydrogen, representing the Preem case and a system lifetime of 10 years for the electro-methanol, representing the Perstorp case. Market price for fossil alternatives are included for comparison, i.e. 50 €/MWh (H2) and 72 €/MWh (Methanol), respectively, where the amount represent the cost that the industries would have had to pay for natural gas based hydrogen and methanol.

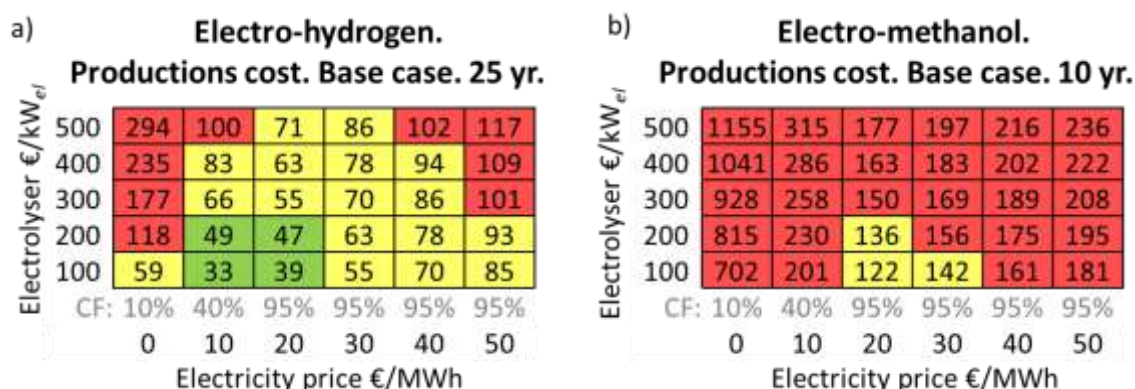


Figure S2. Production costs (€/MWh) for the two electro-fuel base cases (a) the Preem case, with a system life time of 25 years, producing electro-hydrogen, and (b) the Perstorp case, with a system life time of 10 years, producing electro-methanol, assuming different electricity prices and electrolyser investment costs, compared to market price for fossil alternatives where prices for natural gas based hydrogen is assumed to 50 €/MWh and natural gas based methanol to 72 €/MWh. Green marked results indicate a production cost that is equal or lower than the fossil alternative, yellow marked results up to double the fossil price and red marked results higher than double the fossil price.

SAMMANFATTNING

För att nå de nationella målen om en fossiloberoende fordonsflotta 2030, 100 % förnybar kraftproduktion år 2040 och ett klimatneutralt samhälle år 2045 är det viktigt att produktionen av förnybara bränslen, avfossiliseringen av svensk industri i stor skala samt utvecklingen av ett mer flexibelt elsystem med storskalig energilagring nu tar fart. Ett sätt som delvis kan bidra till ett balanserat kraftsystem och delvis till ökad produktion av förnybara substanser, är att utnyttja den ökande tillgången på förnybar, billig el för vattenelektrolys till vätgas (här benämnt som elektro-vätgas) och syrgas.

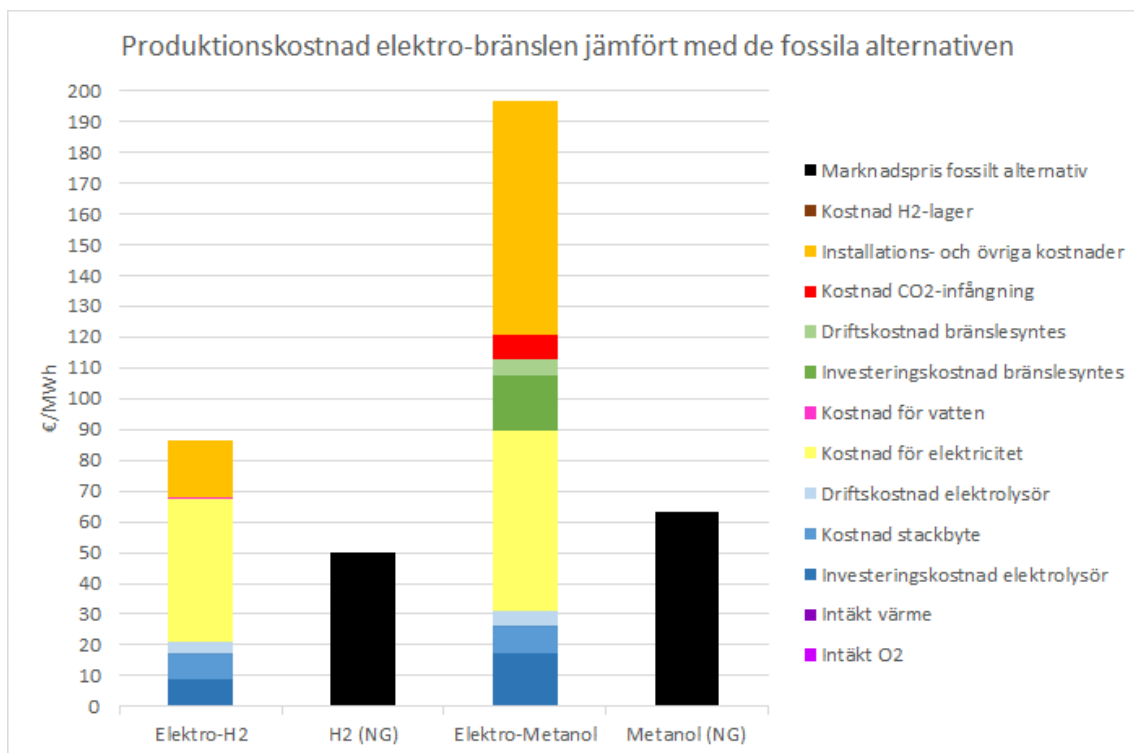
Förnybar elektro-vätgas kan användas som energilager och/eller som bränsle i exempelvis bränslecellfordon, men har troligtvis sin största potential i processer som ersätter fossila råmaterial och/eller energibärare inom olika industriella sektorer, t.ex. stål-, kemi- och biobränsleproduktion. Vidare kan elektro-vätgas användas för att binda större koldioxidutsläpp från t.ex. biogasanläggningar, stål- eller cementindustrin och via s.k. elektrobränsleprocesser (ibland även kallade power-to-gas eller power-to-fuel) generera värdefulla produkter som metan och metanol i en cirkulär ekonomi. De olika applikationerna har olika mognadsgrad, men är i allmänhet långt ifrån en bred kommersiell penetration. Makrofaktorer som fallande elpriser och ökat intresse för koldioxidneutrala produkter och industriella processer har dock initierat ett antal större projekt inom området, t.ex. samarbetet mellan Preem och Vattenfall som syftar till produktion av 3 Mm³ biobränsle 2030, och HYBRIT som syftar till en fossilfri stålproduktion 2045 genom förnybar elektro-vätgas.

Syftet med detta projekt har varit att tillhandahålla en allmän, lättillgänglig sammanfattning av vilka förutsättningar som krävs för att elektro-vätgas skall kunna betraktas som ett lönsamt alternativ för avfossilisering av olika industrisektorer i Sverige. Såvitt vi vet har detta saknats till idag, trots flera större pågående projekt inom området. Analysen i vårt projekt har baserats på ett antal fallstudier med fokus på den svenska kemi- och biobränsleindustrin med svenska cement- och stålindustrin som referenser för att möjliggöra först och främst jämförelser av efterfrågan på elektro-vätgas. Mer specifikt tar analysen avstamp ifrån följande utgångspunkter:

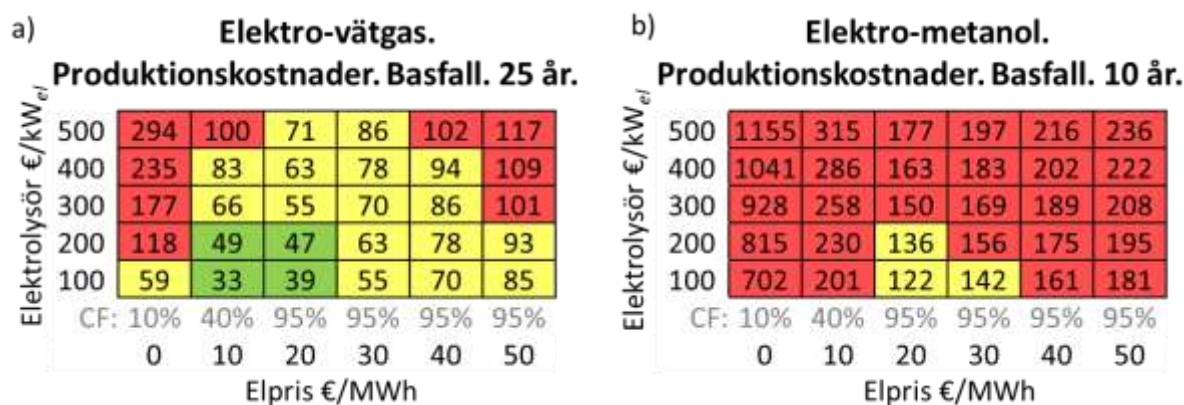
1. Preems behov av förnybar elektro-vätgas för att kunna nå målet om 3 Mm³ biobränsleproduktion 2030.
2. Den svenska RME-produktionens behov av elektro-metanol utifrån dagens produktionsvolym.
3. Perstorps behov av elektro-metanol för sin kemikalieproduktion i Sverige utifrån dagens produktionsvolym.
4. Svensk stålindustris behov av elektro-vätgas för att kunna ersätta de konventionella masugnprocesserna i Luleå och Oxelösund, som utnyttjar fossilt kol och koks, med produktion av s.k. Hydrogen DRI (Direct Reduction Iron). Referensfall 1.
5. Ett tänkt scenario av elektro-metanolproduktion vid svensk cementindustri genom att fånga in och kombinera industrins koldioxidutsläpp med elektro-vätgas. Referensfall 2.

I studien har kvantitativa kostnads- och klimatuppskattningar gjorts genom att använda en beräkningsmodell som utvecklats vid avdelningen för fysisk resursteori, institutionen för rymd-, geo- och miljövetenskap, Chalmers tekniska högskola, med input från industriella intressenter och den öppna litteraturen. Huvudinsikterna från denna studie kan sammanfattas som:

- Att producera vätgas genom vattenelektrolys, liksom att producera metanol från vätgasen, är i dagsläget dyra processer, men eftersom de kan produceras utan fossila CO₂-utsläpp kan marknadsvärdet vara dubbelt så stort som fossil vätgas/metanol, vilket leder till tänkbara affärsmöjligheter (Figur S1-S2 nedan). I en tänkbar framtida situation då tekniken för produktion av elektrobränslen är mogen och det skulle kunna finnas en marknad för syre och restvärme, uppstår resultat som visar att det går att producera elektro-bränslen till lägre kostnad än vad industrin får betala för de fossila alternativen.
- Utnyttjandet av elektrobränslen för att avfossilisera delar av den svenska kemi- och biobränsleindustrin samt delar av den svenska stål- och cementindustrin kräver såväl stora elektrolyskapaciteter som tillgång på förnybar el. Detta i sin tur ställer stora krav på elnäten, vilket är en kritisk utmaning för elektrobränslekonceptet som sådant.
- Att minska koldioxidutsläppen genom att ersätta fossila bränslen och råvaror med elektrobränslen innebär en hög kostnad per undviket ton koldioxidutsläpp. Kostnaden är dock lägre än den straffavgift som inom kort kommer med den s.k. reduktionsplikten. De i denna studie beräknade kostnaderna kan därför betraktas som rimliga från biodrivmedelsindustrins perspektiv om ifall att det blir brist på billigare förnybara bränslen.
- Det är ett känt fenomen att priserna stiger om efterfrågan på en produkt är högre än tillgången, vilket är något att komma ihåg utifall det framöver blir brist på biobränslen (som produceras från en globalt begränsad resurs). En framtida möjlig situation i vilken biobränslen blir allt dyrare skulle kunna leda till att reduktionsplikten först och främst behöver uppfyllas med andra, billigare, förnybara bränslealternativ. I ett sådant framtida scenario skulle t.ex. elektro-bränslen kunna bli kostnadskompatibla.



Figur S1. Produktionskostnad för elektro-bränslen beräknat utifrån studiens s.k. basantaganden (angivna i Tabell 7 i rapporten) och en systemlivslängd på 25 år för elektro-vätgas vilket illustrerar Preems fallstudie och en systemlivslängd på 10 år för elektro-metanol vilket illustrerar Perstorps fallstudie. Marknadspris för de fossila alternativen inkluderas här i jämförande syfte (50 €/MWh respektive 72 €/MWh för H2 och metanol), där beloppen representerar den kostnaden som industrin skulle fått betala om de köpt in naturgasbaserad vätgas och metanol.



Figur S2. Produktionskostnader (€/MWh) för de två elektrobränslefallen (a) elektro-vätgas med en systemlivslängd på 25 år, Preem-fallet och (b) elektro-metanol med en systemlivslängd på 10 år, Perstorp-fallet med basantaganden och olika el- och elektrolysörpriser i jämförelse med fossila alternativ, där priset för naturgasbaserad vätgas respektive metanol antas vara 50 €/MWh och 72 €/MWh. Grönmarkerade resultat indikerar en produktionskostnad som är densamma eller lägre än marknadspriset för det fossila alternativet, gulmarkerade resultat ett pris som är dubbelt det fossila och rödmarkerade resultat mer än det dubbla fossila priset.

LIST OF ABBREVIATIONS

O ₂	Oxygen
H ₂	Hydrogen
H ₂ O	Water
HYBRIT	Hydrogen Breakthrough Ironmaking Technology
CO ₂	Carbon dioxide
CO	Carbon monoxide
CH ₃ OH	Methanol
Electro-H ₂	Hydrogen produced from electricity and water via electrolysis
Electro-methanol	Methanol produced from electro-hydrogen and CO ₂
RME	Rapeseed Methyl Esther
GROT	Forest residues consisting of branches and tops (<i>Swedish: GRenar Och Toppar</i>)
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilisation

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1 INTRODUCTION

1.1 BACKGROUND

In order to reach the national goals of having a fossil-independent vehicle fleet 2030 [1] and a climate neutral society 2045 [2], it is essential that the production of renewable fuels and chemicals as well as de-fossilisation of Swedish industry at large-scale now gain momentum. At the same time, the intermittent power is being expanded with the goal of reaching 100 % renewable power generation 2040 [3], in turn leading to an increasing need for flexibility in the electrical system and large-scale energy storage. One way that could contribute partly to an electrical system in balance and partly to increased production of renewable substances, is to utilise the increasing access of renewable, low cost electricity for electrolysing water into hydrogen and oxygen.

The renewable hydrogen can be used as energy storage or as fuel in e.g. fuel cell vehicles, but may have its utmost potential in processes that replace fossil raw materials and/or energy carriers in various industrial processes such as e.g. steel, chemical and biofuel production. Furthermore, renewable hydrogen can be used to bind larger CO₂ emissions from e.g. biogas plants, steel or cement industry and via so-called electro-fuel processes (also called power-to-gas or power-to-fuel) to generate valuable products such as methane and methanol in a circular economy (see e.g. [4–6]). The various said applications have different degrees of maturity, but are generally still far from a broad commercial penetration. However, macro-factors such as falling electricity prices and increasing interest in carbon-neutral products and industrial processes have initiated a number of major initiatives in this area. A clear Swedish example of the latter is the cooperation between Preem and Vattenfall that investigates the potential of using renewable hydrogen in the production of 3 million m³ biofuels by 2030 [7]. Another example is the HYBRIT (Hydrogen Breakthrough Ironmaking Technology) project, a joint venture company with the same name that Vattenfall runs in co-operation with SSAB and LKAB since summer 2017, aimed to investigate the possibility to produce and store large quantities of renewable hydrogen for the replacement of fossil coke and coal in the steel process [8, 9]. In addition, Wallenstam, Siemens, Göteborg Energi and Innovatum and several others have carried out a pre-study, called the LiquidWind project, targeted to evaluate if it is technically possible and economically viable to build a renewable methanol production unit from wind power, water and CO₂ along the southwest coast of Sweden [10].

The production cost of renewable hydrogen through electrolysis for various industrial processes depends on a variety of parameters, of which the price of the electricity price and the electrolyser having been found to be the most critical [6]. What costs in the different parts of the process (capex and opex) are reasonable for the renewable hydrogen to be considered as a viable alternative depend in turn on the specific use of the hydrogen and the market value of the final products. Although there is still a great deal of research ongoing both internationally and nationally in the field, there is to our knowledge still no summary publicly available that answers questions such as:

- At what cost could renewable hydrogen be considered as interesting as raw material and/or energy carrier for the Swedish chemical and biofuel industry? What does this cost mean to the price of electricity and electrolysis, and how sensitive is the hydrogen production cost for fluctuations in the various sub-costs?
- What is the cost of renewable hydrogen relative to the amount of fossil CO₂ emissions that are avoided through the new hydrogen process?

- What are the differences in costs and climate benefits between using the renewable hydrogen as it is (e.g. for the hydrotreatment of biomass in the biofuel production), and using it combined with CO₂ (fossil or biogenic) for the production of different types of electro-fuels (e.g. methanol)?
- What is the cost (rough estimation) to de-fossilise parts of the Swedish chemical and biofuel industry by use of renewable hydrogen? And what is this cost compared to the costs of producing the amount of renewable hydrogen needed to de-fossilise the Swedish steel industry, or to reduce CO₂ emissions from the Swedish cement industry by means of electro-fuel production as has been considered by Cementa [11, 12]?

This project aims to highlight these issues.

1.2 AIM OF STUDY AND DESCRIPTION OF THE APPLIED METHODOLOGY

The purpose of this project is to provide a public, easily accessible summary of the conditions required in a Swedish context for the renewable hydrogen to be considered a realistic alternative for different industrial sectors. The focus has been on parts of the Swedish chemical and biofuel industry using parts of the Swedish steel and cement industry as references to first and foremost be able to compare the demand for electro-hydrogen.

The project has been carried out by mapping and comparative analyses of the costs and climate benefits. The mapping of processes and necessary in-data were gained through literature surveys and contacts with relevant industries, equipment suppliers and their sub-contractors, etc. The analyses were made by using calculation models developed at the Division of Physical Resource Theory, Chalmers [6]. Examples of in-data of interest in this project are investment and installation costs, operating and maintenance costs, lifetime of investments, and not least relevant assumptions about electricity pricing. For the estimates of climate benefits, in-data for the conventional products that the renewable products are supposed to replace were also required and therefore collected. However, additional cost data for converting existing processes for enabling hydrogen use in e.g. the steel production or biofuel production, does not fit into the project's purposes and aims and has therefore been omitted.

2 DESCRIPTION OF SELECTED INDUSTRIAL PROCESSES

2.1 THE SWEDISH CHEMICAL AND FUEL INDUSTRY

The chemical and fuel production industry in Sweden comprises about 500 companies in refineries, base chemicals and chemical products, plastics and pharmaceutical manufacturing, etc. The sector is today overall energy-intensive and highly dependent on fossil feedstock such as crude oil and natural gas, but with the vision to switch into renewable domestic feedstock and being a key player in the conversion to a bio-based society [13].

In this project, we have chosen to focus the analysis on the biofuel production taking place in the very centre of the Swedish chemical and fuel production industry, located on the southwest coast of Sweden, with the Chemical and Material cluster in Stenungsund (Figure 1) and the large crude oil refineries in Lysekil (Preem) and Göteborg (Preem, St1), respectively. For these industries, there is either already an expressed need for renewable hydrogen, or their fossil input raw material can be directly replaced by renewables originating from water electrolysis and electro-fuel processes. The selected production processes are Preem's biofuel production from lignocellulosic raw materials (1) and Perstorp's RME (Rapeseed Methyl Esther) production (2), which are described in more detail in sections 2.1.1–2.1.2 below. To point out the total volume of electro-fuel needed for the Swedish RME-production, the production of Ecobrånse in Karlshamn is also included in the analysis.

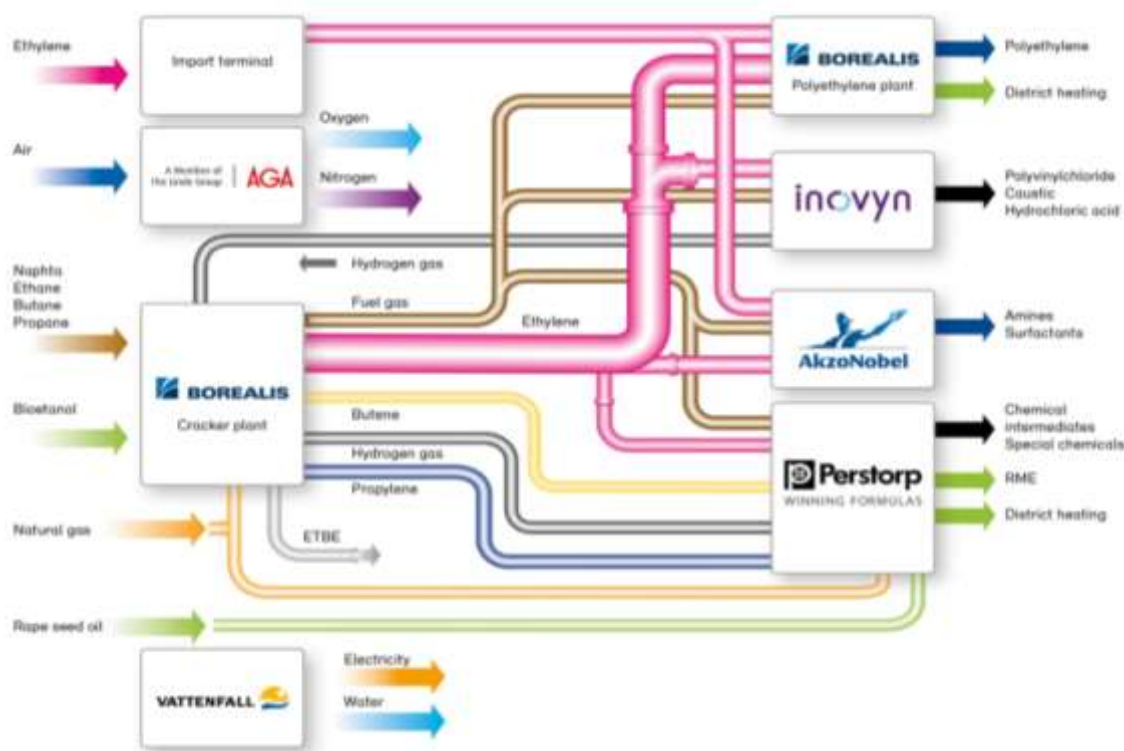


Figure 1. West Sweden Chemicals & Materials Cluster in Stenungsund – Overview of feedstocks, intermediates, processes and products of today. The illustration has been submitted and is published with the permission of Lars Josefsson, West Sweden Chemicals & Materials Cluster in Stenungsund.

2.1.1 *Second generation biofuel (HVO) production in Sweden*

Preem is the largest fuel company in Sweden with a refining capacity of over 18 million m³ of crude oil per year. Their business includes production, sales, distribution and trading and supply of petrol, diesel, fuel oils and renewable fuels. Today, the renewable part (160 000 m³/yr) reaches up to some percentage of the total [14].

Preem works continuously for increasing its share of renewables in its products in combination with increasing the sales of renewable fuels and aims to produce 3 million m³ of biofuel (biodiesel and bio-gasoline) by 2030 [7]. This is an amount that corresponds to their current Swedish sale of gasoline and diesel.

Preem focuses on biomass raw materials such as residual products from the forest and pulp industry, e.g. tall oil and lignin from the pulp black liquor, saw dust from saw mills, and GROT (i.e. branches and tops) from agroforestry. These renewable raw materials commonly contain relative high amounts of oxygen, e.g. 11–12 wt% O₂ (tall oil), 20–30 wt% O₂ (lignin), but also varying amounts of impurities such as sulphur and aromatics, that must be removed in the production process [15]. This removal is carried out by hydrogenation. Depending on the type of raw material and production process used, varying amounts of biomass raw material and hydrogen for the hydrogenation are needed for the bio-fuel production. Preem estimates that they will need 5–8 million tons of raw material and at least 3 TWh hydrogen per year for the production of 3 million m³ biofuels, i.e. $\geq 300 \text{ Nm}^3 \text{ H}_2$ per m³ biofuel product.

Today, the requested amount of hydrogen for Preem's biofuel production is obtained as a side product from a gasoline component plant. This hydrogen production has however long been limiting their step-up in biofuel production and a new hydrogen production plant is therefore under construction in connection to the Preem bio-refinery in Gothenburg [16]. In the new plant, the hydrogen will be produced by gas steam reforming, with gas constituting of approximately 10 % biogas and 90 % natural gas (2017) supplied by the Swedish high-pressure gas grid [17]. In the long term, hydrogen is also planned to be produced via renewable electricity and water electrolysis. Preem estimates that their future need of renewable hydrogen will be able to be met by the Swedish biogas production (that is reformed) in combination with water electrolysis. Furthermore, the production capacity will be entirely demand driven.

A likely future scenario for 2030 is to use hydrogen production from both steam reforming and water electrolysis. When low-cost electricity is available, the ratio of steam reforming can decrease and when the electricity is expensive, the ratio of water electrolysis can decrease with advantage for the ratio of steam reforming. The biofuel production is designed as a continuous process with an availability of approximately 95 % or around 8,300 operation hours per year in average. As the biofuel production technology is new, approximately 8,000 operation hours per year would most probably be accepted as a minimum. Preem estimates that zero or a minor hydrogen storage will be needed to be installed in the biofuel production chain [14]. Input data that is relevant for the analysis of the Preem biofuel production is summarised in Table 1.

Table 1. Summary of input for Preem's biofuel production targeted for 2030. [14]

Target biofuel production	3 Mm ³ /yr
Need of H ₂	≥ 3 TWh /yr, assuming at least 300 Nm ³ H ₂ /m ³ biofuel product
Need of H ₂ Storage	No or minor hydrogen storage
Capacity factor (biofuel production)	≥ 8300 h, i.e. ≥ 95 % availability
Interest rate	8 %
Life-time of investment	25 years

2.1.2 RME production in Sweden

Perstorp is the leading manufacturer of RME in Sweden with Scandinavia's largest production facility located in Stenungsund. The RME plant in Stenungsund has a production capacity of 160,000 tons per year (~ 180,000 m³ per year) and was commissioned in 2007. In order to grow with increased demand for RME, Perstorp has recently acquired and commissioned a production facility in Fredriksund, Norway, which almost doubles the company's RME production capacity [18].

RME is also produced at Ecobräsle's plant in Karlshamn where the production capacity is around 50,000 tons per year (~55,000 m³ per year). Today, however, only about 30 % of this capacity is used with an expected RME output of approximately 15,000 m³ [19].

There are also small-scale plants at several farms around the country.

RME is today used as a low blend fuel (e.g. 7 vol% in Preem Evolution Diesel™), as 100 vol% bio-diesel, (Perstorp's Verdis Polaris™), and as heating oil. At both Perstorp's and Ecobräsle's facilities, RME is produced from rapeseed oil through a thermo-catalytic transesterification process, in which the glycerol in the rapeseed oil is replaced with methanol [18, 20]. In 2016, Perstorp's RME production in Sweden corresponded to a need of around 16,000 tons of methanol (~20,000 m³), of which about 20% were of renewable origin [21]. At the Ecobräsle plant, the corresponding methanol need for the production in 2017 was 1500–2000 m³, of which all was of fossil origin (50 % imported, 50 % recycled) [19]. To put these figures in perspective, the total methanol demand for the Swedish RME production is around 22,000 m³ methanol/yr (~18,000 ton methanol/yr). It corresponds to circa 12 % of the methanol demand for Perstorp's chemical production [21].

Perstorp states that the future capacity utilisation and their need of renewable methanol are difficult to predict since they are entirely dependent on which political incentives that will come in place for vehicle fuels from 2020 [22]. Today, the market price for renewable fuels such as biogas is about three times the price of natural gas. Perstorp reports that the price must come down to less than two times in order to be competitive in the niche. For methanol, the competition is harder and an even lower ratio is required. This is also the case for hydrogen [21].

The input data relevant for the analysis of the Swedish RME production in this study is summarised in Table 2.

Table 2. Input data for the Swedish RME-production, and Perstorp's methanol need for chemical production in Sweden. [19, 21].

Production capacity RME (Perstorp, Stenungsund), 2017	160 000 ton/yr (~ 180 000 m ³ /yr)
Need of methanol for RME-production (Perstorp, Stenungsund), 2017	16 000 ton/yr (~20 000 m ³ /yr @ 100 % production capacity)
Need of methanol for chemical production (Perstorp, Stenungsund), 2017	150 000 ton/yr
Production capacity RME (Ecobräsle, Karlshamn), 2017	50 000 ton/yr (55 000 m ³ /yr)
Need of methanol for RME-production (Ecobräsle, Karlshamn), 2017	1500–2000 m ³ /yr @30 % production capacity
Capacity factor	Continuous process, herein assuming 95 % availability
H ₂ /CH ₃ OH storage	The RME production will be continuous, independent of current electricity cost, thus no or minor storage is assumed to be needed
Interest rate	8 %
Life-time of investment	10 yr

2.2 REFERENCE CASE 1: SWEDISH IRON AND STEEL PRODUCTION

The domestic steel production accounts for about 10 % of Sweden's total CO₂ emissions. The latter corresponds to approximately 5,8 Mton CO₂, out of which around 4,8 Mton originates from the blast furnace processes run by SSAB in Luleå and Oxelösund, respectively, in which new steel is produced from iron ore using fossil coal and coke as reducing agent and fuel [23].

In the effort to reduce the carbon footprint and ultimately obtain a fossil free steel production, several different paths that fully exclude the use of fossils are being investigated. One way is to replace the blast furnace process with hydrogen reduction for DRI (Direct Reduction Iron) production, currently under investigation in HYBRIT [8] and in the European H2FUTURE project [24]. Other strategies are to replace the fossil carbon with tailor-made green coal and syngas/bio-oil from biomass [25, 26] or to apply electrowinning at high temperatures [27]. Besides implementation of new processes replacing the conventional blast furnace process or the use of fossil coke and coal, strategies and techniques that can reduce the CO₂ emissions by application of Carbon Capture and Storage (CCS) and/or Carbon Capture and Utilisation (CCU) are also considered. One CCU application currently under evaluation in the Horizon 2020 FReSMe-project at Swerea mefos (Luleå) is the capture and combination of CO₂ and H₂ from the residue gases, e.g. blast furnace gas, with renewable hydrogen from water electrolysis for the production of electro-methanol [28, 29].

In this project, the Swedish steel industry is used as reference case, and the analysis in this case study is limited to very rough estimations of data (Table 3) assuming implementation of the hydrogen reduction for DRI production that is currently being studied in detail in HYBRIT [8].

Table 3. Input information/data estimated for the reference case (Swedish steel industry).

Electricity need (from ore to crude steel)	15–20 TWh/yr, largely affected by e.g. the distribution DRI/scrap used in the electric arc furnace (EAF), out of which 10–15 TWh/yr will be used for the electrolysis and hydrogen production [30].
Need of H ₂ (total production in Sweden)	7–10 TWh/yr, estimated from 0.65 * Electricity need of 10–15 TWh/yr, where 0.65 is the assumed efficiency of the electrolyser (see Table 7).
Need of H ₂ storage capacity	From a few hours up to days depending on operation conditions, process robustness and production location. Storage in pipelines or underground storage are considered. [8, 31]
Need of O ₂ (by-product of electrolysis)	As a part of their business case, SSAB is investigating different opportunities for O ₂ deposition [31].
Life time of investment	25 years (assumed)
Interest rate	10 % [32]
CO ₂ emissions reported to Naturvårdsverket (Swedish Environmental Protection Agency).	SSAB Luleå (including LUKAB): 3,3 Mton/yr [33] SSAB Oxelösund: 1.5 Mton/yr [33]
CO ₂ emissions estimated to be related to the use of fossil coke and coal in the steel production process	SSAB Luleå: 2,8 Mton/yr, assuming that 85 % of the total CO ₂ -emissions originate from the fossil coke and coal [23] SSAB Oxelösund: 1.3 Mton/yr. Same assumption as for Luleå site.

2.3 REFERENCE CASE 2: SWEDISH CEMENT INDUSTRY

Cement production is a resource and energy intensive industrial process which generates large emissions of CO₂, i.e. 0.67–0.88 tons CO₂ per ton cement produced [34]. It accounts for 4–6 % of global greenhouse gas emissions (5 % in average in Sweden [35]).

The Swedish cement production is carried out at Cementa's plants in Slite, located on the island of Gotland, Skövde in Västergötland, and Degerhamn, located on the island of Öland, with a total production of around 10,000 tons/day. This total production results in nearly 2500 ktons of CO₂ emissions/yr (2016), of which 66 % originates from the calcination process (where the limestone is burnt into lime), and is thus of fossil origin. The remaining CO₂ emissions are biogenic and originate mainly from the combustion required to heat the limestone kiln. The CO₂ concentration of the flue gases varies depending on what type of concrete is being manufactured and the type of factory used, but is usually around 30 %. Tables 4–5 present the cement production and the resulting CO₂ emissions broken down by the respective production sites. The Slite factory is Cementa's largest plant and one of the most modern and environmental friendly cement production plants in Europe. The Degerhamn plant is the oldest and smallest plant with the least opportunity for new investments. The cement production is continuous 24/7 all year in Slite and Degerhamn. In Skövde, the production is currently campaigned due to limiting disposal. [36]

Table 4. Cement production and resulting CO₂ emissions at Cementa's plants in Sweden. [36]

Location cement plant	Slite	Skövde	Degerhamn
Cement production in tons/day (ton/yr), 2016	7000 (2,5 Mton/yr)	2000 (campaign production)	1000 (300 000 tons/yr)
CO ₂ emission in ktons/yr, 2016	1742	369	237

Table 5. Other summarised input data for Cementa's production. [36]

Capacity factor	Continuous process, herein assuming 95 % availability
Concentration CO ₂	~ 30 %
Life time of investment	≥ 25 yr
Need of O ₂ (by-product of electrolysis)	No existing need of O ₂ . A future possibility could be to combine electro-fuel process with oxy-fuel combustion.

Cementa aims to reach a climate neutral production by 2030 with zero CO₂ emissions during the life cycle of the cement product. Their efforts to reach this target involve improving energy efficiency, phasing out virgin fossil fuels, development of new types of cement with lower climate impact, increased build-up in concrete structures and CO₂ separation followed by storage (CCS) or reuse (CCU) (see Figure 2). Data related to CO₂ separation has been used for the model analysis in this project.

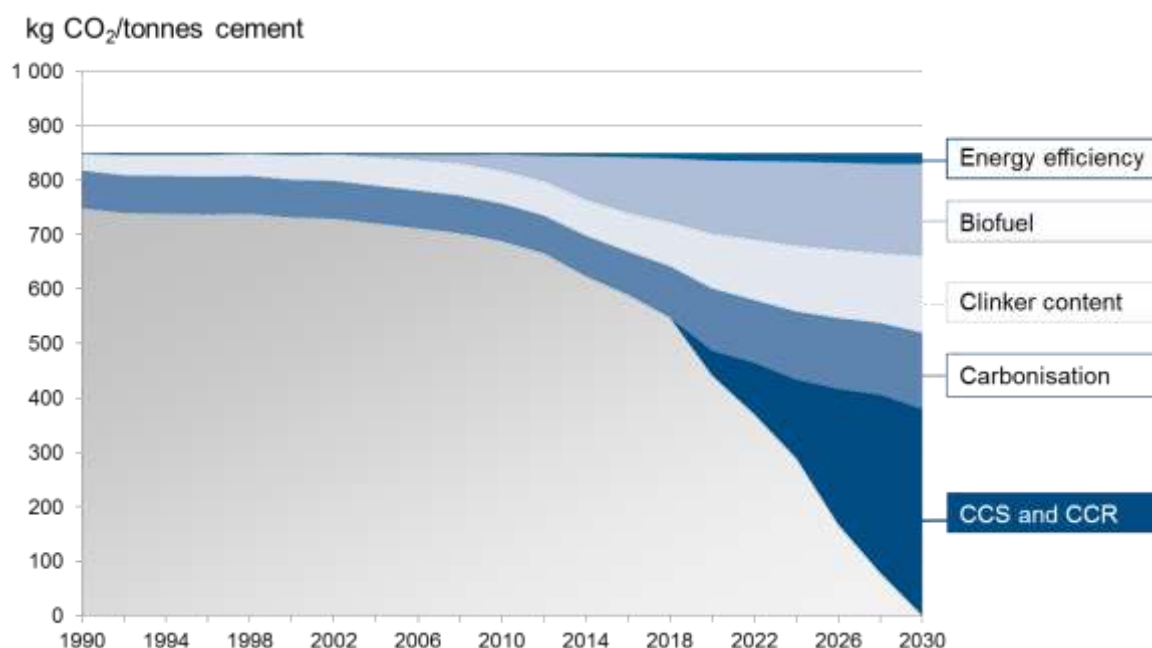


Figure 2. Cementa's vision of zero CO₂ emissions in 2030, published with the permission of Cementa [35].

Today, Cementa looks into different CCS alternatives that could be suitable for their industry. For example, they have recently participated in a pilot project for different post combustion CCS techniques in the cement industry [37]. The project showed promising results and the aim is now set to implement a full-scale amine-based CCS plant. Cementa also looks into the possibility to implement oxy-fuel combustion, i.e. combustion with pure oxygen instead of air, in order to reach a more concentrated CO₂ stream at the same time as a higher combustion temperature can be obtained at lower volume flows and energy losses. Part of this oxygen stream could potentially be produced by water electrolysis and the oxy-fuel process could thus be beneficial to combine with renewable hydrogen and electro-fuel production. However, there is currently no demand for pure oxygen in the cement process. Recently, Cementa initiated a pre-study called CEM-ZERO in cooperation with Vattenfall, aimed to investigate the techno-economic and environmental conditions for implementing electrification of the cement industry in order to reduce the CO₂ emissions. In CEM-ZERO, electrolysis and renewable hydrogen are two out of several (renewable) electrical driven alternatives, e.g. replacing the combustion cement furnaces with micro-waves or induction furnaces, that will be investigated [36, 38].

In reference case 2: Swedish cement industry, the analysis is based on the assumption that the emitted CO₂ (Table 5) is captured and chemically bound to electro-hydrogen for the production of electro-

methanol. The considered process is thus similar to the one considered by Byman [11] and Mohseni et al. [12], except for the fact that electro-methane was in those studies the desirable end-product instead of electro-methanol.

3 APPROACH

In this section the model for the calculations of total production costs is presented along with the chosen input data and made assumptions.

3.1 DESCRIPTION OF ANALYSIS MODEL

The production of electro-fuels can be divided into different steps, where the three main investments are the electrolyser for the production of hydrogen as well as the by-products heat and oxygen from water and electricity (1), the hydrogen storage that may be needed (2), and the fuel synthesis for the production of e.g. methanol from hydrogen and CO₂ (3) (see Figure 3).

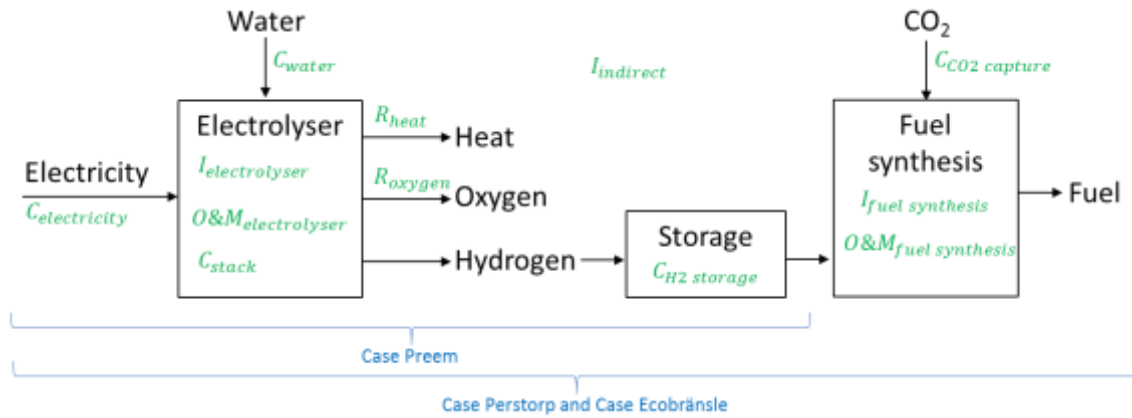


Figure 3. Main components needed to produce electro-fuels, the cost elements (green) building up the total production cost, and system boundaries for the different study cases.

3.1.1 Cost calculations electro-fuels

The total production cost for the electro-fuels C_{efuel} in € per MWh is calculated as follows:

$$C_{efuel} = I_{electrolyser} + O\&M_{electrolyser} + C_{stack} + C_{electricity} + C_{water} + I_{fuel\ synthesis} + O\&M_{fuel\ synthesis} + C_{CO2\ capture} + I_{indirect} + C_{H2\ storage} - R_{heat} - R_{oxygen}$$

Where

- $I_{electrolyser}$ is the annualised direct investment cost of the electrolyser,
- $O\&M_{electrolyser}$ is the operation and maintenance cost for the electrolyser,
- C_{stack} is the annualised cost of stack replacements if the electrolyser's assumed system life time exceeds the stack life time,
- $C_{electricity}$ is the cost of electricity,
- C_{water} is the cost of water needed for the electrolysis,
- $I_{fuel\ synthesis}$ is the annualised direct investment cost of the fuel synthesis,
- $O\&M_{fuel\ synthesis}$ is the operation and maintenance cost for the fuel synthesis,
- $C_{CO2\ capture}$ is the cost to capture CO₂,
- $I_{indirect}$ represents the annualised indirect investment costs for the facility including e.g. engineering and construction, equipment and installation costs, fees, de-ionisation of water, and safety, and
- $C_{H2\ storage}$ is the cost for hydrogen storage.

The production cost can be reduced if there is a market for by-products, where R_{heat} is the revenue from selling excess heat, and R_{oxygen} is the revenue from selling excess oxygen.

$I_{electrolyser}$ (€/MWh) is calculated as

$$I_{electrolyser} = I_{H2} \cdot \frac{r}{1 - (1 + r)^{-n}} \cdot \frac{1}{\gamma \cdot 8760}$$

where I_{H2} is the investment cost for the electrolyser (€/MW_{H2}),
 r is the interest rate,
 n is the electrolyser's system life time (yr),
 γ is the capacity factor (share of max capacity) and 8760 the number hours per year.

I_{H2} is calculated as $I_{H2} = I_{el}/\eta$

where I_{el} is the investment cost for the electrolyser (€/MW_{el}) and
 η is the conversion efficiency (H₂_{LHV}/electricity input).

$O\&M_{electrolyser}$ (€/MWh) is calculated as

$$O\&M_{electrolyser} = \beta \cdot I_{H2} \cdot \frac{1}{\gamma \cdot 8760}$$

where β is an operation and maintenance factor (share of investment cost).

C_{stack} (€/MWh) is calculated as

$$C_{stack} = I_{H2} \cdot \alpha \cdot m \cdot \frac{r}{1 - (1 + r)^{-n}} \cdot \frac{1}{\gamma \cdot 8760}$$

Where α is a stack replacement factor (share of investment cost), and
 m is the number of stack replacements needed calculated from the annual operating hours, the stack life span and the electrolyser system life span. It is rounded up to the nearest integer, as

$$m = \text{ROUNDUP}\left(\frac{n}{\gamma \cdot 8760 \cdot \tau}; 0\right) - 1$$

Where τ is the electrolyser's stack life time (h). For an electrolyser with a system life time of $n=25$ years, there will be two stack replacements if the stack life time $\tau = 75,000$ h.

$C_{electricity}$ (€/MWh) is calculated as $C_{electricity} = E/\eta$

where E is the electricity price (€/MW_{el}), and
 η is the conversion efficiency (H₂_{LHV}/electricity input).

C_{water} (€/MWh) is calculated as $C_{water} = D_{water} \cdot W$,

where D_{water} is the demand for water (ton/MW_{H2}), and
 W is the cost for water (€/ton).

$I_{fuel\ synthesis}$ is calculated as

$$I_{fuel\ synthesis} = I_{fuel} \cdot \frac{r}{1 - (1 + r)^{-n}} \cdot \frac{1}{\gamma \cdot 8760}$$

where I_{fuel} is the investment cost for the fuel synthesis reactor (€/MW_{fuel}).

$O\&M_{fuel\ synthesis}$ (€/MWh) is calculated as

$$O\&M_{fuel\ synthesis} = \beta \cdot I_{fuel} \cdot \frac{1}{\gamma \cdot 8760}$$

$C_{CO2\ capture}$ (€/MWh) is calculated as $C_{CO2\ capture} = D_{CO2} \cdot V$

where D_{CO2} is the demand for CO₂ (tCO₂/MWh_{fuel}), and
 V is the cost for CO₂ capture (€/tCO₂).

$I_{indirect}$ (€/MWh) is calculated as

$$I_{indirect} = ((I_{H2} + I_{fuel})\pi - (I_{H2} + I_{fuel})) \cdot \frac{r}{1 - (1 + r)^{-n}} \cdot \frac{1}{\gamma \cdot 8760}$$

where π is an experience factor for indirect investment costs.

$C_{H2\ storage}$ (€/MWh) is calculated as

$$C_{H2\ storage} = \frac{S_{H2} \cdot \lambda}{F}$$

Where S_{H2} is the hydrogen storage cost (€/Nm³),
 λ is the storage size for the chosen case (Nm³), and
 F is the planned hydrogen production per year (MWh/yr).

λ (Nm³) is calculated as $\lambda = \kappa \cdot G$

Where κ is the storage capacity (h), and
 G the planned hydrogen production (Nm³/h).

G (Nm³/h) is calculated as

$$G = \phi \cdot \frac{1}{\gamma \cdot 8760} \cdot \frac{1}{k}$$

Where ϕ is the planned hydrogen production (kWh/yr), and
 k is a conversion constant between Wh and Nm³ in LHV (3 kWh/Nm³).

R_{heat} is calculated as $R_{heat} = H \cdot \Psi$

Where H is the heat revenue (€/MWh_{heat}), and
 Ψ is the excess heat produced in the electrolyser (MWh_{th}/MWh_{H2}).

R_{oxygen} is calculated as $R_{oxygen} = O \cdot \theta$

Where O is the oxygen revenue (€/ton), and
 θ is the produced oxygen in the electrolyser (ton/MWh_{H2}).

3.1.2 Cost calculations fossil alternatives

To compare the production costs of electro-fuels with fossil alternatives, costs for two natural gas based options have been calculated, natural gas based hydrogen (NG-H2) and natural gas based methanol (NG-MeOH):

C_{NG-H2} (€/MWh) is calculated as

$$C_{NG-H2} = P_{NG-H2} \cdot \frac{1}{k} \cdot 1000$$

where P_{NG-H2} is the market price of natural gas based hydrogen (€/Nm³), and
 k is a conversion constant between Wh and Nm³ in LHV (3 kWh/Nm³).

$C_{NG-MeOH}$ (€/MWh) is calculated as

$$C_{NG-MeOH} = P_{NG-MeOH} \cdot \frac{1}{\delta} \cdot h$$

Where $P_{NG-MeOH}$ is the market price of natural gas based methanol (€/ton),
 δ is the energy content (GJ/ton), and
 h is a conversion constant between Wh and Joule (3.6 GJ/MWh).

3.1.3 Calculate cost per avoided CO₂ emissions

If the electro-fuels are produced using CO₂ neutral electricity and CO₂ from renewable sources, and if they replace fossil alternatives, it can be said that fossil CO₂ emissions are avoided. The amount of avoided CO₂ equals the amount of CO₂ that would have been emitted from the fossil alternative. The additional cost that arises from using electro-fuels instead of fossil alternatives, divided by the amount of avoided CO₂, gives result on cost per avoided CO₂ emissions ($C_{avoided}$) expressed in €/tCO₂. Cost per ton avoided CO₂ when using electro-hydrogen is:

$$C_{avoided_H2} = \frac{(C_{electro-H2} - C_{NG-H2})}{\sigma_{NG}/\eta_{NG-H2}}$$

Where $C_{electro-H2}$ (€/MWh) is the production cost for the electro-hydrogen,
 C_{NG-H2} (€/MWh) is the production cost for the fossil alternative (natural gas based hydrogen),
 σ_{NG} is the emission factor for natural gas (0.203 tCO₂/MWh_{NG}), and
 η_{NG-H2} is the conversion efficiency from natural gas to hydrogen (0.8).

Cost per ton avoided CO₂ when using electro-methanol is:

$$C_{avoided_MeOH} = \frac{(C_{electro-MeOH} - C_{NG-MeOH})}{\sigma_{NG}/\eta_{NG-MeOH}}$$

Where $C_{\text{electro-MeOH}}$ (€/MWh) is the production cost for the electro-methanol,
 $C_{\text{NG-MeOH}}$ (€/MWh) is the production cost for the fossil alternative (natural gas based methanol),
 σ_{NG} is the emission factor for natural gas (0.203 tCO₂/MWh_{NG}), and
 $\eta_{\text{NG-MeOH}}$ is the conversion efficiency from natural gas to methanol (0.7).

3.2 DESCRIPTION OF ELECTRO-FUEL COMPONENTS AND CHOICE OF INPUT DATA FOR BASE-CASE AND SENSITIVITY ANALYSIS

The main component needed when producing electro-fuels is the electrolyser. Other components needed, depending on the process, are the hydrogen storage, the fuel synthesis, and the carbon capture technology. These electro-fuel components are described below.

3.2.1 *Electrolysis*

There are today in principle three different types of electrolysis technologies: Alkaline Electrolysis Cell (AEC), Polymer Electrolyte Cell (PEM) and Solid Oxide Electrolyte Cell (SOEC). The main features of each technology are here described in short and summarised in Table 6.

The three electrolysis technologies differ in terms of operating conditions, efficiency, flexibility, maturity and cost, and are thus suited to different industrial systems, projects and, not least, time frames. The main advantages of AEC as of today, compared to PEM and SOEC, are low capital costs, availability of large plant sizes, and long life time. The disadvantages are low current density and high maintenance costs as the system is highly corrosive containing 20–30 vol% potassium hydroxide (KOH). The cold-start times are from minutes to hours, and a large transient operation window is possible but can be associated with problems [39].

PEM is the most dynamic electrolysis technology (shortest start-up time, largest operating range). It has no corrosive electrolyte and it also enables hydrogen and oxygen production with a higher purity than the AEC does. However, PEM has not been on the market for as long as AEC, so there are fewer manufacturing companies, and they are mainly adapted for lower capacities [40]. Today, PEM electrolyzers at the MW scale are available [39]. Other drawbacks of PEM are the shorter life time and the significantly higher capital cost.

Finally, SOEC is the most energy efficient but also the least mature technology. The high operating temperature requires access to high-quality heat, at least at start-up and part load, and is therefore suitable for integration with other high-temperature processes, e.g. thermochemical synthesis of methanol. Thanks to the high operating temperature, SOEC's can also be utilised for co-electrolysis, where the reactions CO₂ to CO and H₂O to H₂ take place simultaneously, leading to the production of syngas. SOEC's main disadvantages are the long start-up time and the fact that it is significantly less thermo-mechanical stable than both the AEC and PEM, meaning that the technology is not very suitable for fluctuating or intermittent operation [39].

In our base case analysis, we assume that the AEC technology is used (500 €/kWe, efficiency = 65 %). However, in the sensitivity analysis, we consider the usage of both PEM and SOEC, illustrated in this case by studying the impact of a significantly higher electrolysis investment cost (1000 €/kWe) and a significantly higher efficiency (up to 90 % as is expected for SOEC), respectively (see Table 6).

Table 6. Summary of technical performance and cost of three electrolysis technologies. Data are based on information found in the open literature [6, 40] and input from electrolyser suppliers [42, 43].

	AEC	PEM	SOEC
Operation temperature (°C)	60–80	50–80	600–1000
Efficiency (from power to hydrogen, LHV)	60–80	60–80	90–95
Start-up time from cold condition	Minutes to hours	Seconds to minutes	Hours
Operation range of full capacity (%)	20–100	5–100	Low flexibility
Electrolysis products	H ₂ , O ₂ , heat	H ₂ , O ₂ , heat	H ₂ , O ₂ , heat (H ₂ O electrolysis) CO, syngas, heat (H ₂ O and CO ₂ electrolysis)
Maturity	commercial	commercial	Pilot-demo
Stack life-time hours	60,000–80,000	10,000–80,000	Data not available.
CAPEX (€/kW _e)	500–1000	1000–2000	Uncertain, e.g. 4000–11,000 [44], 400–1000 [45]
O&M costs	2–5 % of the initial CAPEX	2–5 % of initial CAPEX	Data not available.

3.2.2 Carbon capture

Carbon for the production of electro-fuels such as electro-methanol can be captured from different point sources and activities that give rise to surplus capturable CO₂. Examples of carbon sources are biogas upgrading plants, flue gases from fossil and biomass combustion plants, industrial plants such as iron, steel and cement, as well as geothermal activity, air, and seawater. The CO₂ concentrations in the different sources range from very small (400 ppm in air) up to almost 100 % from biogas plants. In this analysis, the carbon source is assumed to be either CO₂ in flue gases from industrial combustion plants (25–30 % in concentration), where CO₂ can be captured at a cost of 30–50 €/ton [6, 46].

3.2.3 Fuel synthesis

As described in previous chapters, hydrogen and CO₂ can be combined into different hydrocarbon compounds via different fuel synthesis processes, such as methane synthesis (e.g. Sabatier), methanol synthesis, and Fischer-Tropsch synthesis. In this study, the focus is on electro-hydrogen, where no fuel synthesis is needed, and electro-methanol.

Methanol can be produced from CO₂ in one or two thermochemical steps. The two-step process starts by converting CO₂ to CO with the reversed water gas shift (RWGS) reaction, followed by hydrogenation to methanol.

In methanol synthesis by direct hydrogenation of CO₂, i.e. the one-step process, there are generally three competing reactions: The direct methanol synthesis from CO₂, $\text{CO}_2 + 3\text{H}_2 \rightarrow \text{CH}_3\text{OH} + \text{H}_2\text{O} + 40.9\text{kJ}$ (at 298 K) (1), the hydrogenation of CO, $\text{CO} + 2\text{H}_2 (\text{g}) \leftrightarrow \text{CH}_3\text{OH} + 90.7\text{kJ}$ (at 298 K) (2), and the RWGS reaction (3).

The typical CO₂ conversion in a fixed-bed reactor is in the range of 20–40% without recycling, and CO formation is significant, resulting in the need to recycle unreacted CO₂, CO, and H₂ to the feed stream in order to reach nearly full CO₂ conversion and high methanol selectivity [47]. The resulting product is a mixture of methanol and water that needs to be distilled to yield more pure methanol.

The investment costs for methanol synthesis have been estimated at 200–1200 €/kW_{fuel} for different plant sizes in the literature [48–52]. In our base-case analysis, we have assumed a cost of 1000 €/kW methanol representing a relatively small facility of 5 MW [6].

3.2.4 Hydrogen storage

Hydrogen can be stored in different ways; in compressed tanks or liquid hydrogen tanks (cryo), as metal hydrides or activated carbons, in pipelines and underground, e.g. in salt cavities. The storage technologies differ in pressure and temperature, geometric foot print, flexibility and complexity, availability, operation and installation cost, etc. For small hydrogen volumes, the most common way for storing hydrogen is to use compressed tanks up to 700 bars. Cryo-tanks could also be an option to consider for smaller to medium volumes as they offer storage with a very low geometric foot print, but with the serious drawback of being a high energy consuming alternative (around 30 % of the LHV of H₂ for the liquefaction). For larger hydrogen volumes, pipelines or underground storage at ≤ 50 bars are more commonly considered [53].

Since industrial production processes are continuous, we have assumed that no hydrogen storage is needed in the base case of this study. In practice, at least some buffering storage will most probably be needed for technical reasons. To get an indication of how storage may impact the results, calculations were therefore also made for a 10 h hydrogen storage size at two different costs (1 and 46 €/Nm³, respectively) representing underground storage and storage in 45 bar compressed tanks [53, 54].

3.2.5 Choice of input data

Data chosen and assumptions made for calculations in this study are summarised in Table 7, presenting both base case assumptions and alternatives studied in the sensitivity analysis.

Table 7. Summary of assumptions made in this study.

	Unit	Base case	Sensitivity analyses
Data for electrolysis			
I_{el} investment cost electrolyser (alkaline, alternative PEM)	€/kW _{el}	500	300, 1000
β operation and maintenance factor (share of investment cost)	-	0.04	
α stack replacement factor (share of investment cost)	-	0.5	
τ electrolyser's stack life time	h	75,000	
η conversion efficiency electrolyser	H _{2,LHV} /electricity input	0.65 ^a	0.55, 0.75, 0.90
D_{water} demand for water, electrolysis (assuming 2X stoichiometric demand)	ton/MWh _{H2}	0.54	
W cost for water	€/ton _{water}	1	
H heat revenue	€/MWh _{heat}	0	30
Ψ excess heat produced in the electrolyser	MWh _{th} /MWh _{H2}	0.46	
O oxygen revenue	€/ton _{O2}	0	50
θ produced oxygen in the electrolyser	ton _{O2} /MWh _{H2}	0.24	
Data for methanol synthesis			
I_{fuel} investment cost methanol synthesis reactor	€/MW _{fuel}	1000	
β operation and maintenance factor (share of investment cost)	-	0.04	
$\eta_{methanol}$ conversion efficiency methanol synthesis	Methanol _{LHV} /H ₂ input	0.79	
Demand for hydrogen, electro-methanol (LHV), used in Reference case 2 (Cement industry)	MWh _{H2} /MWh _{methanol}	1.3	
D_{CO2} demand for carbon dioxide, electro-methanol	ton _{CO2} /MWh _{methanol}	0.28	
V cost for CO ₂ capture (10–50% concentration)	€/ton _{CO2}	30	
Hydrogen storage			
S_{H2} hydrogen storage cost (no storage alternative large scale underground storage or container)	€/Nm ³	0	1, 46
F planned hydrogen production per year (Preem)	TWh/yr	3	
κ hydrogen storage capacity	h	10	
Other data			
E is the electricity price	€/MWh _{el}	30	20, 50
r interest rate	-	0.08	
n system life time of components Preem vs Perstorp	years	25, 10	
γ capacity factor (share of max capacity over a year)	-	0.95	
π experience factor for indirect investment costs	-	3.14	2
k conversion constant (LHV)	kWh/Nm ³	3	
P_{NG-H2} market price natural gas based hydrogen	€/Nm ³	0.15	
$P_{NG-MeOH}$ market price natural gas based methanol	€/ton	400	
h conversion constant between Wh and Joule	GJ/MWh	3.6	
δ energy content methanol	GJ/ton	20	
η_{NG-H2} conversion efficiency natural gas to hydrogen	-	0.8	
$\eta_{NG-MeOH}$ conversion efficiency natural gas to methanol	-	0.7	

^a The efficiency can be based on either LHV or HHV, depending on industrial sector and application of fuel. In this study, for reasons of simplicity, the electrolyser efficiency is always based on the LHV. The impact of basing the electrolyser efficiency on HHV instead can be read from Figure A.6–A.7, where higher values of the electrolysis efficiency have been assumed in the analysis.

4 RESULTS AND DISCUSSION

In the following, the results of analysis of the Preem and the Perstorp base-cases are presented and discussed. These results are then compared to the results obtained for the selected reference cases, i.e. production of electro-H₂ for the Swedish steel industry and production of electro-methanol using the CO₂ emissions of the Swedish cement industry. The discussion also includes the results obtained in the sensitivity analysis, for which related figures and tables are displayed in the appendix.

4.1 SWEDISH CHEMICAL AND BIOFUEL INDUSTRY

Two base cases are calculated: the Preem case and the Perstorp case (see Figures 4–5). All input data are identical for the two cases (see Table 7), except for the electro-fuel system lifetime, for which Preem assumes 25 years and Perstorp 10 years. The system lifetime affects the number of stack replacements needed for the electrolyzers; two stack replacements are needed in the Preem case and one replacement is needed in the Perstorp case. For simplicity reasons, figures are always presenting results for both electro-hydrogen and electro-methanol along with their fossil alternatives, leading to that results are presented for both 10 and 25 years for the two cases. As mentioned above, figures presenting results from the sensitivity analyses can be found in the appendix.

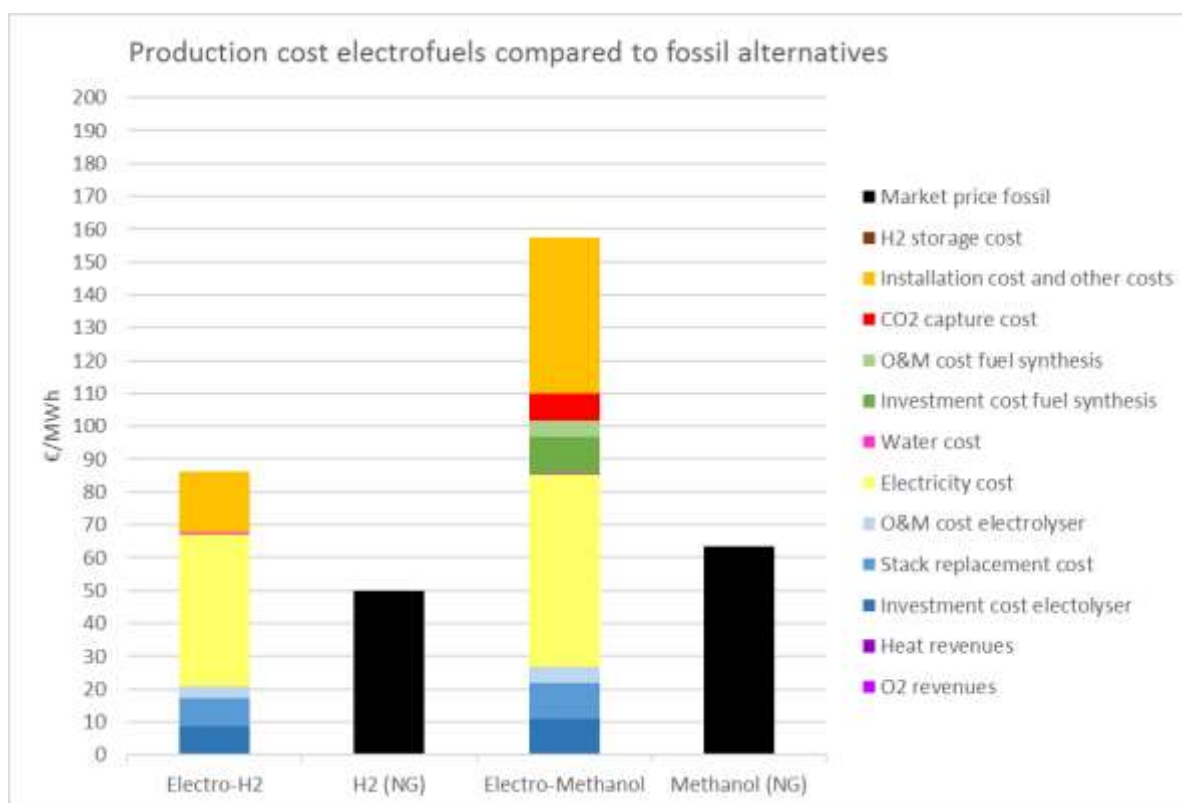


Figure 4. Production cost for electro-H₂ and electro-methanol, using base case assumptions and a system life time of 25 years, representing the Preem case. Market price for fossil alternatives are included for comparison.

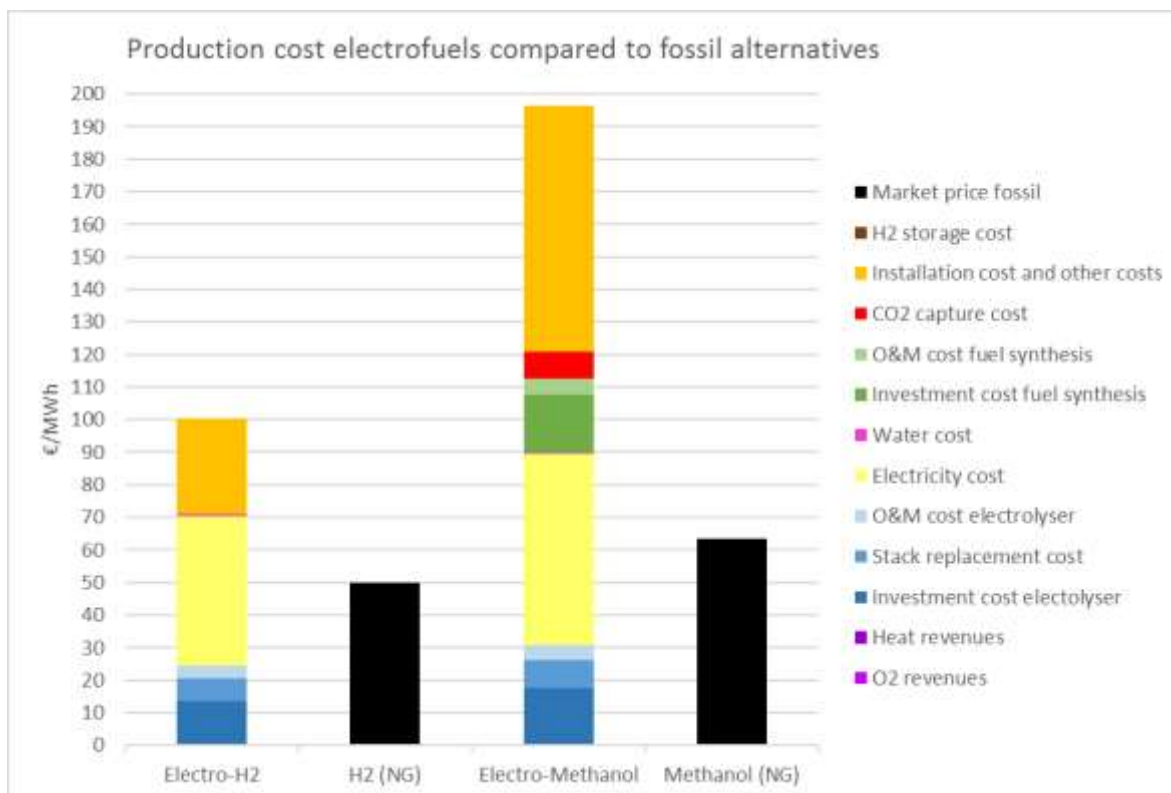


Figure 5. Production cost for electro-hydrogen and electro-methanol, using base case assumptions and a system lifetime of 10 years, representing the Perstorp case. Market price for fossil alternatives are included for comparison.

From figures 4–5 it can be seen that the cost for electricity is the dominating post making up for approximately half of the total production cost for electro-hydrogen and approximately one third of the total production cost for electro-methanol. Also the experienced-based post *Installation cost and other costs* is large. *Water cost* and *CO₂ capture cost* are relatively small posts. When assuming a system lifetime of 10 years (Figure 5), the production costs increases compared to when assuming a system lifetime of 25 years (Figure 4). On the other hand, only one stack replacement is needed when assuming a system lifetime of 10 years leading to that the post *Stack replacement cost* decreases, slightly compensating for the increase in total cost. A more precise comparison of the two base cases is presented in Table 8 (production costs) and Table 9 (avoided CO₂), where also the corresponding data for Ecobrånslé's RME production is included for illustrating the needs of electro-hydrogen for the major part of the Swedish RME-production.

Table 8. Results of the comparison of production costs in the Preem and Perstorp cases.

	Fuel production cost (€/MWh)	Times more expensive, compared to fossil alternative	More expensive compared to 25 years life time (€/MWh)
<i>Assuming a system life time of 25 years</i>			
Electro-H ₂ (case Preem)	86	1.7	-
H ₂ (based on natural gas)	50	-	-
Electro-methanol	158	2.2	-
Methanol (based on natural gas)	72	-	-
<i>Assuming a system life time of 10 years</i>			
Electro-H ₂	101	2.0	8
H ₂ (based on natural gas)	50	-	-
Electro-methanol (case Perstorp)	197	2.7	30
Methanol (based on natural gas)	72	-	-

Table 9. Results of the comparison of avoided CO₂ emissions in the Preem, Perstorp and Ecobräsle cases.

	Case Preem electro-hydrogen	Case Perstorp electro-methanol	Case Ecobräsle electro-methanol
Demand H ₂ or methanol (GWh/yr)	3000	88,889	8,889
Emission factor natural gas based hydrogen or methanol (kgCO ₂ /MWh)	254	271	271
Avoided CO ₂ from not using fossil alternatives in the production plant (kton CO ₂ /yr)	762	24	2,4
Demand for electro-H ₂ (GWh/yr)	3000	107	11
Electrolyser capacity (MW)	360	13	1
<i>Assuming a system life time of 25 years</i>			
Additional cost, i.e. electro-fuel minus fossil (€/MWh)	36	86	86
Tot additional cost for the production plant (M€/yr)	109	8	0.8
Cost per avoided CO₂ (€/tCO₂)	143	316	316
<i>Assuming a system life time of 10 years</i>			
Additional cost, i.e. electro-fuel minus fossil (€/MWh)	51	125	125
Tot additional cost for the production plant (M€/yr)	152	11	1
Cost per avoided CO₂ (€/tCO₂)	199	460	460

From Table 8 it can be seen that the Preem base case production cost for electro-hydrogen is 1.7 times higher than the natural gas based hydrogen. In the Perstorp case, the production cost for electro-methanol is 2.7 times more expensive than natural gas based methanol. From the contacts with the industry made in this study, industrial representatives have indicated that a market price for renewable electro-fuels may lie in the range of a factor of 2 times higher than the fossil alternatives. Results from the base cases therefore indicate that there might be a market for electro-fuels.

From the sensitivity analyses, tests to change one parameter at the time of the most uncertain input data (see right hand column in Table 7), showed that the “times-more-expensive-factor vs. the fossil alternative” for electro-hydrogen (the Preem case) varies in the range of 1.2–2.5, indicating that there may be circumstances where electro-hydrogen is cost-competitive (see Table A.2 in the appendix for details). Representing the lower end of the range are the cases where an ultimate conversion efficiency is used (i.e. SOEC), and the case when revenues for both waste heat and oxygen are included. The highest factor is obtained for the case assuming the higher investment cost for the PEM electrolyser. Furthermore, when it comes to electro-methanol¹, the “times-more-expensive-factor vs. the fossil alternative” varies in the range of 1.7–2.9, where the lowest factor is obtained for the case assuming revenues for the by-products and the highest factor is obtained assuming higher investment cost for the electrolyser. Another interesting result of the sensitivity analysis is the fact that if all optimistic assumptions are combined, the production costs for both electro-hydrogen and electro-methanol become significantly less than for the fossil alternatives, ending up with factors 0.5 and 0.8, respectively (see Table A.2 in Appendix).

¹ NB! Not exactly the Perstorp case, since assumption on 25 years, however still illustrative as a study case.

The cost for avoided CO₂ emissions is 143 €/tCO₂ for electro-hydrogen in the Preem case and 460 €/tCO₂ for the electro-methanol in the Perstorp case (Table 9). These costs can be compared to the costs that the industry may face when the reduction duty will be introduced in July 2018², where the maximum penalty is 7 SEK/kg CO₂ equivalents, i.e. approximately 700 €/tCO₂eq [54–57].

Table 9 also gives an overall notion of how large the demand for hydrogen, and need for investments at Preem, Perstorp and Ecobräsle would be if they would all go for the electro-fuel option. If so, in total, these three fuel producers would invest in an electrolyser capacity of 374 MW_e.

Table 2 shows that Perstorp needs an additional 150,000 ton methanol per year for other chemical production in Stenungsund. If this amount of methanol is produced as electro-methanol, it leads to a demand for 150,000 ton methanol · 5.6 MWh/ton (LHV) = 833,333 MWh methanol/yr. Since 1.2 MWh H₂ is needed to produce each MWh electro-methanol, it leads to a demand of 833,333 · 1.2 = 1,000,000 MWh electro-hydrogen. The electrolyser capacity needed to produce this amount of H₂ is 120 MW_e. In the base case scenario, the additional cost for producing electro-methanol instead of natural gas based methanol is 188–72 = 116 €/MWh leading to a total additional cost of 833,333 MWh/yr · 116 €/MWh = 97 M€/yr. Avoided CO₂ is then 833,333 MWh/yr · 0.271 ton CO₂/MWh = 226 kton CO₂/yr.

As can be seen from the results in Table 9, the total demand for electro-hydrogen for electro-fuel production at Preem, Perstorp and Ecobräsle requires a total electrolysis capacity of 374 + 120 = 494 MW_e; a huge capacity that is almost of the same order as for example the capacity of the nuclear reactor Oskarshamn 1 (500 MW). The annual electricity need to supply the electrolyzers at the different sites would be 4.62 TWh (Preem) + 0.16 TWh (Perstorp RME) + 0.02 TWh (Ecobräsle) + 1.54 TWh (Perstorp chemical production), adding up to a total of 6.3 TWh/yr (approximately 4.5 % of Sweden's electricity demand in 2016 (140 TWh) [58]), indicating a great challenge for the power sector and the electricity grid.

Total additional cost for Preem, Perstorp and Ecobräsle if they all would produce electro-fuels instead of using natural gas based alternatives is 109+10+1+97= 217 M€/year.

Total avoided CO₂ for Preem, Perstorp and Ecobräsle if they all would produce electro-fuels instead of natural gas based alternatives is 762+24+2+226 = 1014 kton CO₂/yr. This corresponds to almost twice the amount of CO₂eq emitted from Swedish aviation sector in 2016 [59].

The calculated figures for the overall Swedish chemical and biofuel industries' (in this study represented by Preem, Perstorp and Ecobräsle) potential use of electrolysis and electro-fuels are summarised in Table 10.

4.2 SWEDISH CEMENT AND STEEL INDUSTRY

Also in the cement and steel industry it is possible to reduce CO₂ emissions by the use of electro-hydrogen and electro-methanol production. In this project, the Swedish cement and steel industry are presented as reference cases using very rough estimations.

² A policy for reduction of GHG from conventional gasoline and diesel, in Swedish called Reduktionsplikt.

4.2.1 Swedish cement industry

In this rough exercise, it is assumed that the CO₂ emissions produced in the cement industry will be captured and used as feedstock to produce electro-methanol. From Table 4 it can be seen that the three Swedish cement plants Slite, Skövde and Degerhamn together emit $1742+369+237 = 2348$ kton CO₂/yr. According to Hansson et al [46], 90 % of emitted CO₂ can be captured from cement facilities leading to that $2348 \cdot 0.9 = 2113$ kton CO₂/yr can be captured from the three cement plants. If all capturable CO₂ is used to produce electro-methanol, this amount of CO₂ can, together with 9.72 TWh hydrogen, form 7.66 TWh of electro-methanol. As a comparison, the Swedish road transport consumes approximately 80 TWh fuel per year meaning that electro-methanol from the cement industry could supply approximately 10 % of the fuel demand for the domestic road transport.

If all needed hydrogen would be produced as electro-hydrogen it would demand an electrolyser capacity of 1168 MW_e and a use of 14,95 TWh electricity per year. This amount of electricity corresponds to approximately 11 % of all electricity used in Sweden today.

The cost for this production of electro-methanol would be $7.66 \text{ TWh/yr} \cdot 158 \text{ €/MWh} = 1210 \text{ M€/year}$ assuming base case costs listed in Table 7 and with a 25-year system lifetime. As a rough estimation for the income from sold electro-methanol, the market price for natural gas based methanol has been used as well as a separate calculation assuming that renewable methanol has a market value of two times the fossil (section 2.1.2). Income from sold electro-methanol is therefore first estimated to $7.66 \text{ TWh/yr} \cdot 72 \text{ €/MWh} = 551 \text{ M€/year}$. The production cost minus the revenue is in the first case $1210 - 551 = 658 \text{ M€/year}$. In the second case, assuming that a market value for renewable methanol is twice the one for fossil methanol, the income from sold electro-methanol is $7.66 \text{ TWh/yr} \cdot 144 \text{ €/MWh} = 1103 \text{ M€/year}$. The production cost minus the revenue is then $1210 - 1103 = 107 \text{ M€/year}$.

Assuming that the produced electro-methanol would replace natural gas produced methanol, and that electro-methanol is sold at the same price as fossil methanol, this would lead to 2075 kton CO₂/yr avoided, and savings of 317 €/tCO₂. If electro-methanol can be sold for twice the price of fossil methanol, the avoided emissions would still be 2075 ktonCO₂/yr, with savings of 52 €/tCO₂.

Alternatively, the produced electro-methanol could be blended into conventional gasoline. The emission factor for oil-based gasoline is similar to natural gas-based methanol, and for simplicity reasons that same factor is used when avoided CO₂ emissions are calculated, resulting in 271 kg CO₂/MWh or 2075 kton CO₂/yr. If the electro-methanol replaces gasoline, and is sold at the same price as gasoline (assuming a Rotterdam price of 425 \$/m³ converted to 48 €/MWh), this would lead to savings of 407 €/tCO₂. If electro-methanol can be sold at twice the price of gasoline, the savings would be 179 €/tCO₂.

The calculated figures for the Swedish cement industry's potential use of electrolysis and electro-fuels are summarised in Table 10.

4.2.2 Swedish steel industry

This rough exercise takes its starting point from the information given in Table 3 that 10–15 TWh electricity may be used annually to produce hydrogen for the Swedish steel industry to become fossil free by replacing the blast furnace process with the hydrogen DRI (Direct Reduction Iron) production. Assuming that the hydrogen will be produced from splitting water in electrolyzers (in this study defined as electro-hydrogen) with a conversion efficiency of 65 %, it can be assumed that 7–10 TWh of

electro-hydrogen could potentially be produced per year. To produce this hydrogen amount, a total electrolyser capacity of 781–1172 MW_e is required.

To find the production cost per MWh of electro-hydrogen, a “steel-base-case” is calculated assuming the same base case assumptions as presented in Table 7, with the additions of a 10 h hydrogen large-scale underground storage (1€/Nm³ H₂), an oxygen revenue of 50 €/ton O₂, and a system life time of 25 years. Results for the production cost are presented in Figure 6. The production cost of electro-hydrogen is shown to be 75 €/MWh (i.e. 2,5 €/kg), i.e. the same as has been estimated in HYBRIT [8].

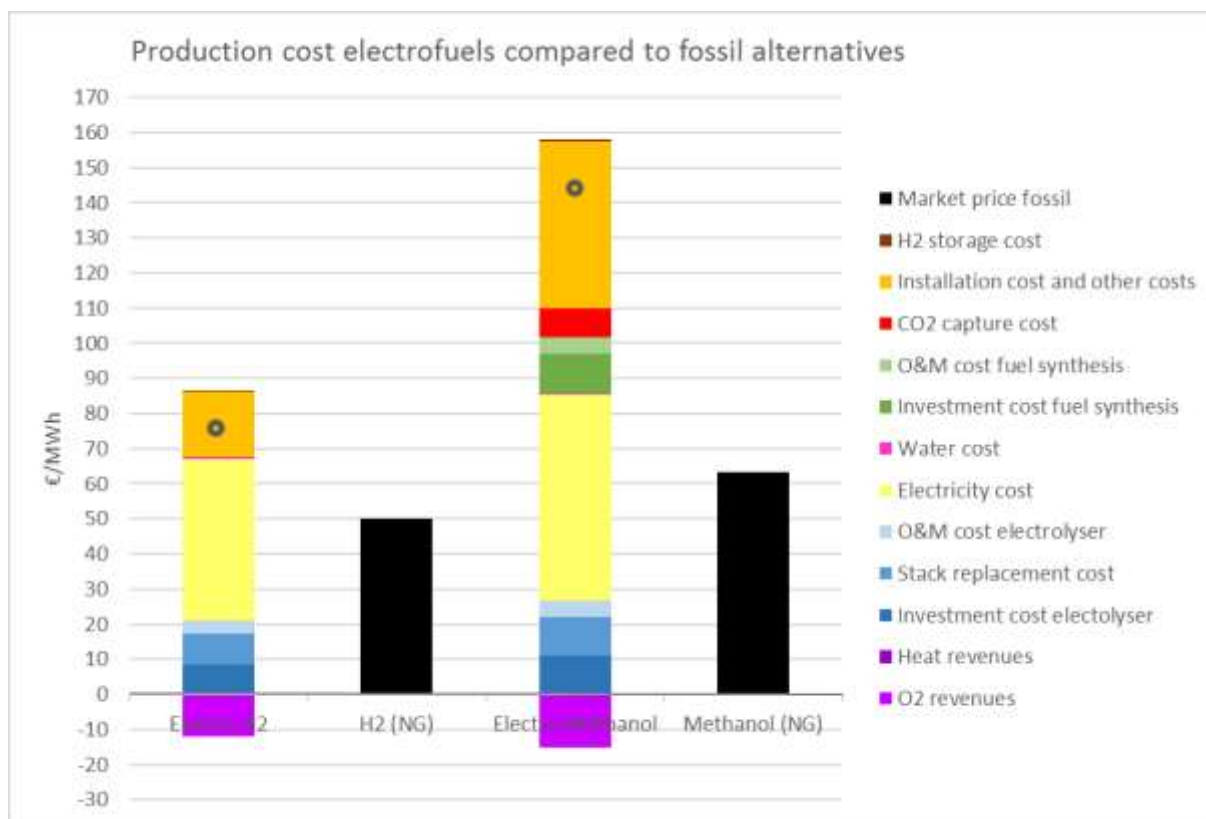


Figure 6. Production cost for electro-hydrogen and electro-methanol, using the “steel-base-case” assumptions. Market price for fossil alternatives are included for comparison. Note that total costs include the minus bar for revenues (75 and 143 €/MWh for the electro-H₂ and electro-methanol, respectively).

The total production cost for the 7–10 TWh electro-hydrogen is 488–731 M€/yr, respectively. Since no information is found for the savings of replacing the blast furnace process (e.g. coal and coke), with hydrogen DRI production, the additional cost used when calculating the cost per avoided CO₂ emission is 488–731 M€/yr.

In Table 3, current CO₂ emissions related to the use of fossil coke and coal in the steel production process is estimated to 2.8 Mton CO₂/yr from the Luleå plant and 1.3 Mton CO₂/yr from the Oxelösund plant, adding up to 4.1 Mton CO₂/yr. Calculating total production cost (M€/yr) divided by 4.1 Mton CO₂/yr gives a cost for avoided CO₂ emissions of 119 and 178 €/tCO₂ for the demand of 7 and 10 TWh electro-hydrogen, respectively.

The calculated figures for the Swedish steel industry’s potential use of electrolysis and electro-fuels are summarised in Table 10.

4.3 COMPARISON BIOFUELS, CHEMICAL, CEMENT AND STEEL

Main results on costs, electrolyser capacity, and avoided CO₂ for the three different types of industries, are summarised in Table 10.

Table 10. Results of the potential use of electro-fuels of the overall Swedish chemical and biofuel industries compared to the cement and steel industry. The Swedish chemical and biofuel industry refers to the so called Preem case, the Perstorp case, incl. Ecobrånslé, and the methanol demand of Perstorp for other chemical production.

	Electrolyser capacity (MWe)	Avoided CO ₂ (kton CO ₂ /yr)	Additional cost (M€/yr)	Cost per avoided CO ₂ (€/tCO ₂)
Chemical and biofuel industry	494	1014	217	214 ^{a)}
Cement industry	1168	2075	658 ^{b)} 844 ^{c)} 107 ^{d)} 370 ^{e)}	317 ^{b)} 407 ^{c)} 52 ^{d)} 179 ^{e)}
Steel industry ^{f)}	781–1172	4100	488–731 ^{g)}	119–178

^{a)} This cost per avoided CO₂ is here a value calculated from the total cost and total avoided emissions whereas values for electro-hydrogen and electro-methanol earlier have been presented separately.
^{b)} Assuming that market price for electro-methanol is the same as fossil methanol and that electro-methanol substitute natural gas based methanol.
^{c)} Assuming that market price for electro-methanol is the same as fossil methanol and that electro-methanol substitute oil based gasoline.
^{d)} Assuming that market price for electro-methanol is doubled that of fossil methanol and that electro-methanol substitute natural gas based methanol.
^{e)} Assuming that market price for electro-methanol is doubled that of fossil methanol and that electro-methanol substitute oil based gasoline.
^{f)} Lower and higher range corresponds to assuming a need for 7 and 10 TWh electro-H₂ respectively.
^{g)} It should be noted that this cost most likely is too high since no cost reduction is assumed for technologies that can be avoided if hydrogen replaces the blast furnace process and the utilisation of coke and coal.

From Table 10 it can be seen that the demand for hydrogen and/or methanol is large in the Swedish chemical and biofuel industries as well as in the cement and steel industry. If this total demand would be met by electro-hydrogen and electro-methanol, the total electrolyser capacity would be 494+1168+1172=2834 MWe. As comparison, the four nuclear reactors at Ringhals has a capacity of 860+870+1000+1000=3730 MW [60].

The size of total electrolyser capacity needed, for the industrial processes analysed in this study, demand an electricity supply of 36 TWh/yr which corresponds to approximately 26% of Sweden's electricity demand of today. The latter is a huge challenge for the power sector and the electricity grid, which reveals that the generation of renewable electricity is a great challenge also for the production of electro-fuels.

From Table 10 it can also be seen that the production of electro-fuels has a great potential for avoided CO₂, 1014+2075+4100 = 7.2 Mton CO₂/yr, an amount that corresponds to as much as half of the total CO_{2eq} emitted from the Swedish road transport in 2016 [59].

4.4 WHICH PRICES OF ELECTRICITY AND ELECTROLYSERS ARE NEEDED TO MATCH THE PRICE OF FOSSIL ALTERNATIVES?

In these exercises, the production cost of the two studied electro-fuel cases are analysed with the aim of identifying which combination of electricity and electrolyser prices that could match the price of fossil alternatives.

In the first exercise, the production costs are compared to the market prices for natural gas based alternatives, where hydrogen is assumed to be bought for 50 €/MWh and methanol for 72 €/MWh. The electricity price is in this case varied in the range of 0–50 €/MWh in combination with electrolyser investment cost (CAPEX) in the range of 100–500 €/kW_{el}. No other parameters are changed from the base case assumptions (presented in Table 7).

The results are presented in Figure 7a–d. The coloured fields indicate if the production costs are equal or lower than the fossil alternatives, if they are within the range or up to double the fossil price (indicated from the industry as a market price for the renewable option), or if they are higher than double the fossil price. It should be noted, however, that these low electricity prices are expected in the future only and that electricity prices below 20 €/MWh only can be combined with low capacity factors (which will increase the production cost per MWh hydrogen, as presented in the figure). Scenarios for the Swedish electricity price area SE2 [61] have been used to investigate which capacity factor that can be combined to which electricity price assumption (Figure 8a–b). There it can be seen that by 2030, an annual average electricity price of 20 €/MWh is possible, thus assumptions on electricity prices of 20 €/MWh and higher can be matched with a capacity factor of 95%. An electricity price of 10 €/MWh can be found for 40% of the hours over the year and extremely low electricity prices (close to zero) can be found for 10% of the hours over the year, leading to a match of 10% and 40% capacity factors for the electricity price assumptions of 0 and 10 €/MWh, respectively.

For the Preem case (Figure 7a), applying a willingness to pay 10–20 €/MWh for the electricity, it seems to be cost-competitive to produce electro-hydrogen instead of buying fossil hydrogen, if electrolyser CAPEX is at 200 €/kW_{el} or below. For the Perstorp case (Figure 7d), no combination of electricity price and electrolyser CAPEX was found that could generate a production cost capable of competing with the market price of fossil methanol. However, at electricity prices between 20–30 €/MWh and electrolyser CAPEX at 200 €/kW_{el} or below, it seems possible to produce electro-methanol below double the market price of fossil methanol, i.e. in the same size of order as biomass-based methanol.

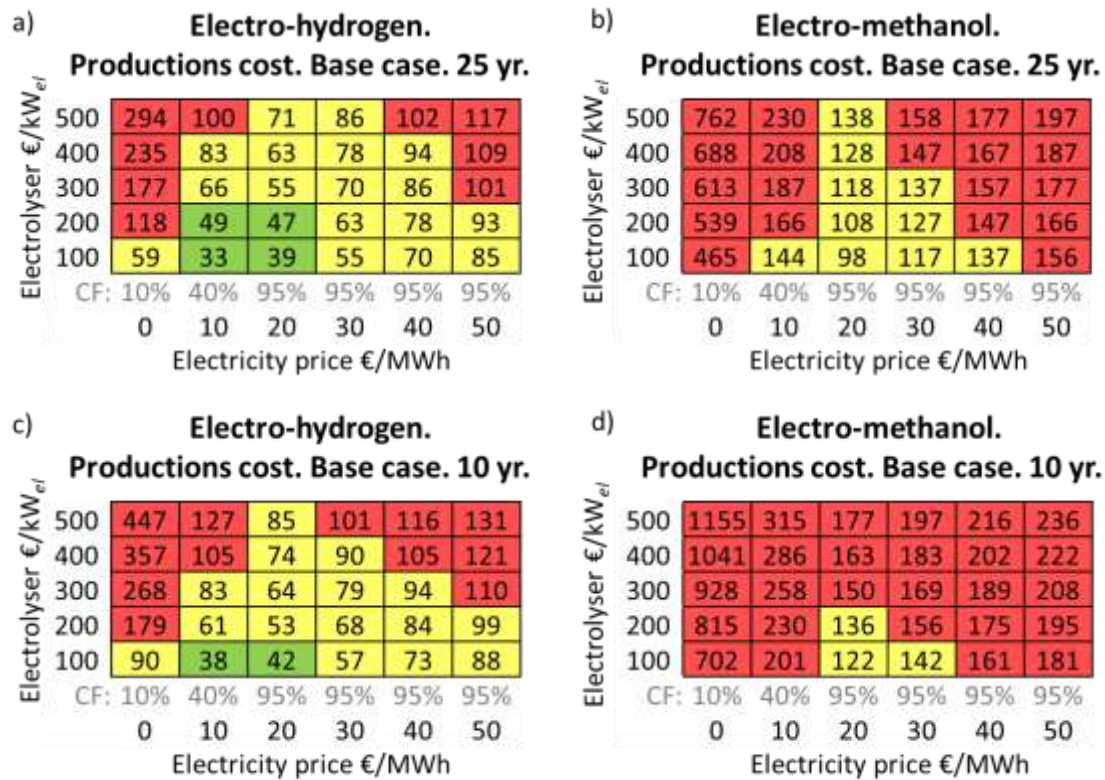


Figure 7. Production costs (€/MWh) assuming different electricity prices and electrolyser investment costs for the assumption of 25 years system lifetime for a) electro-hydrogen (Preem case), and b) electro-methanol, and for the assumption of 10 years system lifetime for c) electro-hydrogen, and d) electro-methanol (Perstorp case). Production costs are compared to market prices for two fossil alternatives: natural gas based hydrogen (50 €/MWh) and natural gas based methanol (72 €/MWh). Green boxes indicate the result of a production cost equal to, or lower than, the fossil alternative. Yellow boxes indicate results of a production cost up to double the price of the fossil alternative, and red boxes a result higher than double the fossil price of the fossil alternative.

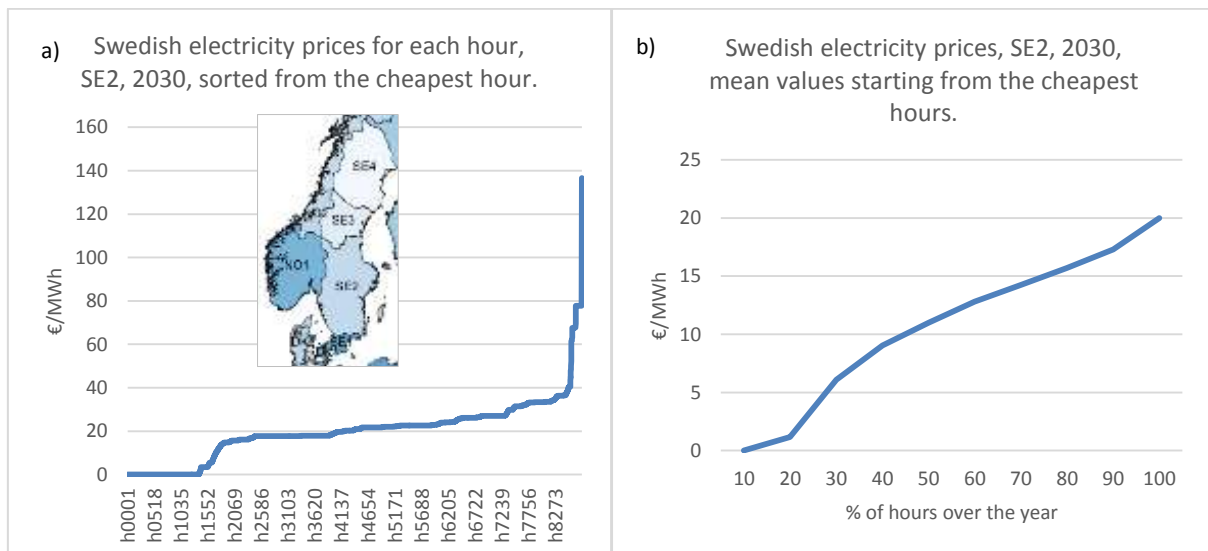


Figure 8. Swedish electricity prices per hour expected for the electricity price area SE2 by 2030: a) sorted from the cheapest hours, and b) plotted as mean values starting from the cheapest hours. The plots are based on data from Taljegård (2018) [61].

A significantly more positive picture appears if the assumptions are adjusted to a future situation where the technology is more mature and there is a market for excess oxygen and heat. All input data is kept the same as in the base case, apart from that we assume a 50 MW methanol synthesis reactor (instead of 5 MW). Scale effects reduce the investment cost from 1000 €/kW_{methanol} to 500 €/kW_{methanol}, if combined with the assumption that mature technologies can reduce the experience factor for indirect investment costs from 3.14 down to 2, as well as income for sold oxygen (50 €/ton) and heat (30 €/MWh). Figure 9 shows these circumstances for when both electro-hydrogen and electro-methanol can be produced at lower cost compared to the price that industries pay for natural gas based hydrogen and methanol as of today.

For the Preem case (Figure 9a) it seems to be cost-competitive to produce electro-hydrogen instead of buying fossil hydrogen, already at current investment costs for electrolyzers (500 €/kW_{el}), if electricity prices are in the range of 10-20 €/MWh. At electricity prices around 30 €/MWh the production cost of electro-hydrogen can compete if investment cost for electrolyzers are reduced to 400 €/kW_{el} or below. For the Perstorp case (Figure 9d) it seems to be cost-competitive to produce electro-methanol, instead of buying fossil methanol, if the electricity price is around 20 €/MWh and if investment costs for electrolyzers are reduced to 400 €/kW_{el} or below. Also, at electricity prices between 10–50 €/MWh and electrolyser CAPEX between 100 and 500 €/kW_{el}, it seems possible to produce electro-methanol below double the market price of fossil methanol, making it cost-competitive to biomass-based methanol.

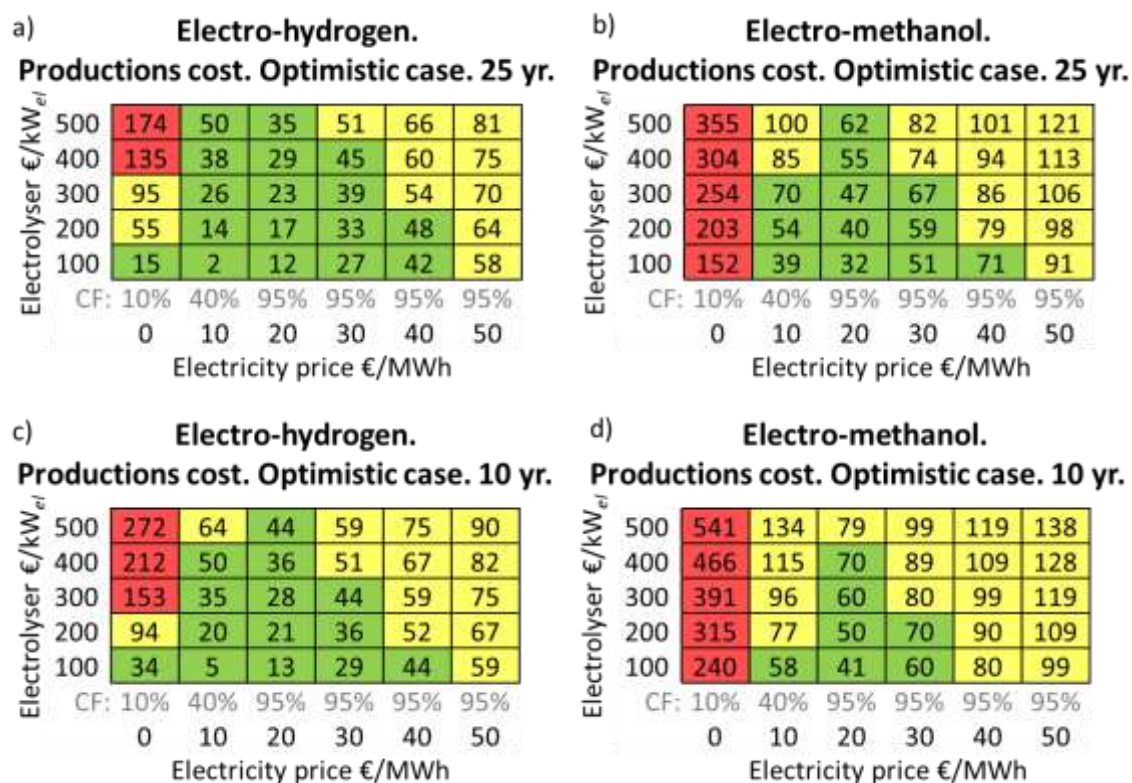


Figure 9, a-d. Production costs (€/MWh) in the optimistic case (see text for description) for different electricity prices and electrolyser investment costs assuming 25 years system lifetime for a) electro-hydrogen (Preem case) and b) electro-methanol, and assuming 10 years system lifetime for c) electro-hydrogen, and d) electro-methanol (Perstorp case). Production costs are compared to market prices for fossil alternatives where the prize of natural gas based hydrogen and natural gas based methanol are assumed to be 50 €/MWh and 72 €/MWh, respectively. Green boxes indicate results of a production cost equal to or lower than the market prize for the fossil alternatives. Yellow boxes indicate results of a production cost up to double the market prize for the fossil alternatives, and red boxes indicate results higher than double the market prize for the fossil alternatives.

5 CONCLUSIONS

The purpose of this work has been to provide a summary of the conditions required in a Swedish context for hydrogen from renewable power and water electrolysis to be considered as a viable alternative for various industrial sectors. The analysis is a case study and has been focused on parts of the Swedish chemical and biofuel industry. Parts of the Swedish steel and cement industry have been used as references in order to be able to compare the potential demand for electro-hydrogen. To enable quantitative cost and climate comparisons, a mathematical model developed at Chalmers has been used, along with input from industrial stakeholders and open literature. The main conclusions are summarised as answers to the key questions raised in the introduction of this report.

1. *At what cost could renewable hydrogen be considered as interesting as raw material and/or energy carrier for (parts of) the Swedish chemical and biofuel industry?*
2. *What does this cost mean to the price of electricity and electrolysis, respectively, and how sensitive is the hydrogen production cost for fluctuations in the various sub-costs?*

Assuming that renewable fuels may be attractive if they have a production cost equal to or below double that of natural gas based fuels, the cost can be maximum 100 €/MWh for electro-hydrogen and maximum 144 €/MWh for electro-methanol.

For electro-hydrogen, a production cost around or below 100 €/MWh appear in the base case and all sensitivity runs except for case 2, assuming the more expensive PEM electrolyzers with a cost of 1000 €/kW and case 4, assuming a higher electricity price of 50 €/MWh. On the border with a production cost of 102 and 105 €/MWh are the sensitivity runs (5) assuming a lower electrolyser conversion efficiency of 55% and case 11, assuming a more expensive storage (a 45 bar container hydrogen storage at a cost of 46 €/Nm³).

For electro-methanol, a production cost around or below 144 €/MWh does not appear in the base case but in six sensitivity runs: case 1, assuming a lower investment cost for electrolyser (300 €/kW_{el}); case 3 assuming a lower electricity price (20 €/MWh); case 6, assuming higher electrolyser conversion efficiency (75%); case 7, assuming SOEC electrolyser conversion efficiency (90%); case 9, assuming lower experience factor for indirect investment costs (a factor of 2); and case 12, assuming that excess heat and oxygen can be sold at 30 €/MWh and 50 €/ton O₂, respectively.

When systematically testing combinations of different cost assumptions for the two most dominating posts, i.e., the electricity price and the electrolyser investment costs, some combinations result in an electro-hydrogen production cost equal to or lower than that for which industries can buy fossil hydrogen. Such low production costs can be found when electricity prices are in the range of 10–20 €/MWh combined with an electrolyser CAPEX at 200 €/kW_{el} or below (see Figure 7a).

For the Perstorp case, we found no combination of electricity price and electrolyser CAPEX that could generate a production cost able to compete with the market price of fossil methanol. However, at electricity prices between 20–30 €/MWh and electrolyser CAPEX at 200 €/kW_{el} or below, it seems possible to produce electro-methanol below double the market price of fossil methanol and thereby in the same size of order as biomass-based methanol (see Figure 7d). To get a production cost of electro-methanol lower than that of natural gas based methanol, it is not enough to combine low electricity prices with low investment cost on electrolyzers, but also other parameters need to be adjusted.

Analysing the production costs for different electricity prices and electrolyser CAPEX in a potential future situation where the technology is more mature and there is a market for excess oxygen and heat, we find circumstances for when both electro-hydrogen and electro-methanol can be produced at lower cost compared to what industries pay for natural gas based hydrogen and methanol. For the Preem case (electro-hydrogen) this appears already at current investment costs for electrolyzers (500 €/kW_{el}) if electricity prices are in the range of 10–20 €/MWh or at the combination of electricity prices around 30 €/MWh and electrolyser CAPEX at 400 €/kW_{el} or below (see Figure 9a). For the Perstorp case (electro-methanol) this appears for the combinations of an electricity price around 20 €/MWh and electrolyser CAPEX at 400 €/kW_{el} or below (see Figure 9d).

3. *What is the cost of renewable hydrogen relative to the amount of fossil CO₂ emissions that are avoided through the new electro-hydrogen process?*

Cost per avoided CO₂ emissions lies in the order of 52–407 €/tCO₂ for both the Swedish chemical and biofuel industries and the cement and steel industry (Table 10). Sensitivity runs show a range of 41–298 €/tCO₂ for electro-hydrogen and 180–501 €/tCO₂ for electro-methanol. This can be compared to the costs that the industry may face when the reduction duty is introduced in July 2018, where the maximum penalty is 700 €/tCO₂eq. This study points to that all types of electro-fuels considered in this study ends up with production costs below the suggested penalty level.

4. *What are the differences in costs and climate benefits between using the renewable hydrogen as it is (e.g. for hydrotreatment of biomass in the biofuel production), and using it combined with fossil or biogenic CO₂ for the production of different types of electro-fuels (e.g. methanol)?*

The production cost is lower for electro-hydrogen than electro-methanol. Electro-hydrogen also shows a lower cost for avoided CO₂ resulting in 143 €/tCO₂ in the Preem case. Electro-methanol in the Perstorp case results in 460 €/tCO₂ for avoided CO₂ emissions (from not using natural gas based alternatives). However, from the Cementa case, it can be seen that the cost per avoided CO₂ is 52 €/tCO₂ given the assumptions that the market price for electro-methanol is twice that of fossil methanol, and that electro-methanol substitutes natural gas based methanol.

5. *What is the cost (rough estimation) to de-fossilise parts of the Swedish chemical and biofuel industry by using renewable hydrogen?*

In order to avoid fossil CO₂ emissions, the additional cost for producing renewable electro-fuels for the Swedish chemical and biofuel industry analysed in this study, calculated as total production cost minus avoided costs for the fossil alternatives, is approximately 200 M€/yr.

6. *What is this cost (referring to previous question) in comparison to the costs of producing the amount of renewable hydrogen needed to de-fossilise the Swedish steel industry or reduce the CO₂ emissions from the Swedish cement industry by means of electro-methanol production?*

In order to avoid fossil CO₂ emissions from the cement and steel industry, the additional cost for producing renewable electro-fuels lies in the ranges of 107–844 and 488–731 M€/yr, respectively, where the cost range for the steel industry may be too high since it is unclear what costs that can be avoided by using electrofuels. See Table 10 for detailed comparisons.

Main insights from this study can be summarised as:

- Producing hydrogen using electrolyzers, as well as methanol from the hydrogen, are currently expensive processes, but since the electro-fuels can be produced without CO₂ emissions the market value may be double that of fossil hydrogen/methanol leading to possible business opportunities. In a potential future situation where the electro-fuel technology is more mature and there is a market for excess oxygen and heat, we find circumstances for when electro-fuels can have a lower production cost compared to what industries pay for natural gas based hydrogen/methanol. Using electro-fuels for the purpose of de-fossilizing parts of the Swedish chemical and biofuel industry as well as parts of the Swedish steel and cement industry, demands a large amount of electrolysis capacity and use of fossil free electricity. This would in turn put pressure on the existing electricity grid. This constitutes a challenge for the electro-fuel concept.
- Reducing CO₂ emissions through the substitution of fossil fuels and feedstock with electro-fuels has a high cost per avoided CO₂. However, it is far below the penalty cost from the coming reduction duty policy. The cost may therefore be judged as reasonable, from the biofuel industry's perspective, if there is a lack of cheaper renewable options.
- That prices will rise if the demand for a product is higher than the supply potential, is something to keep in mind if there will be a future lack of biofuels (which is a limited resource). In the future, a situation may arise where biofuels are more expensive, leading to that the reduction duty policy first and foremost will be fulfilled with options that are less expensive than biofuels. This is where electro-fuels may be cost-compatible.

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APPENDIX: RESULTS FROM SENSITIVITY ANALYSIS

Figures presented in this Appendix are generated from the Preem base case varying one uncertain parameter at the time to improve the understanding of if the uncertainty have a large impact on the results. The alternative parameters tested in the sensitivity analysis are listed in Table A.1 and results are presented in Figures A.1–A.12 as well as in Tables A.2–A.3.

Table A.1. List of alternative assumptions for the sensitivity analysis.

		Unit	alternative	Base case
1	I_{el} lower investment cost electrolyser (potential cost reduction for future alkaline)	€/MW _{el}	300	500
2	I_{el} higher investment cost electrolyser (PEM)	€/MW _{el}	1000	500
3	E lower electricity price	€/MWh _{el}	20	30
4	E higher electricity price	€/MWh _{el}	50	30
5	η lower conversion efficiency electrolyser	H ₂ _{LHV} /electricity input	0.55	0.65
6	η higher conversion efficiency electrolyser	H ₂ _{LHV} /electricity input	0.75	0.65
7	η ultimate conversion efficiency electrolyser (SOEC)	H ₂ _{LHV} /electricity input	0.90	0.65
8	τ lower electrolyser's stack life time	h	65,000	75,000
9	π lower experience factor for indirect investment costs	-	2	3.14
10	S_{H_2} assume need for hydrogen storage cost (large scale underground storage)	€/Nm ³	1	0
11	S_{H_2} assume need for hydrogen storage cost (45 bar container)	€/Nm ³	46	0
12	H and O heat and oxygen revenue	€/MWh _{h12eat} and €/ton _{O2}	30 and 50	0
13	Combining all optimistic assumptions (1,3,6,9,12)	-	-	-

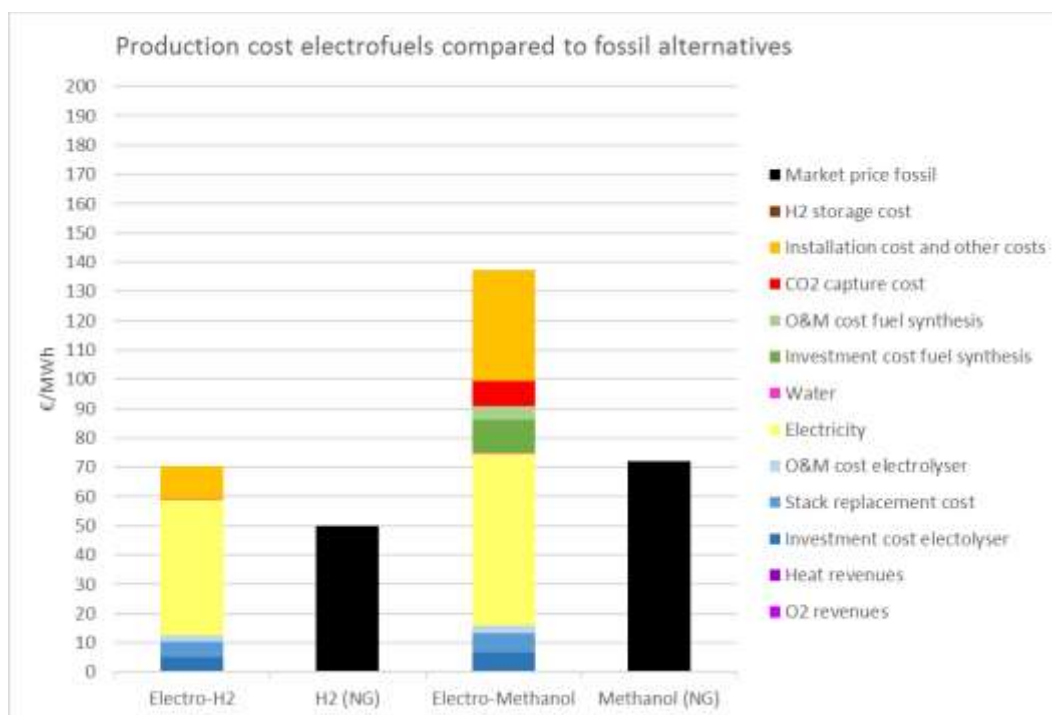


Figure A.1. Production cost for electro-hydrogen and electro-methanol, using base case assumptions for the Preem case, as presented in Table 7, apart from here assuming *lower investment cost electrolyser (potential cost reduction for future alkaline, 300 €/kW)*. Fossil alternatives are included for comparison.

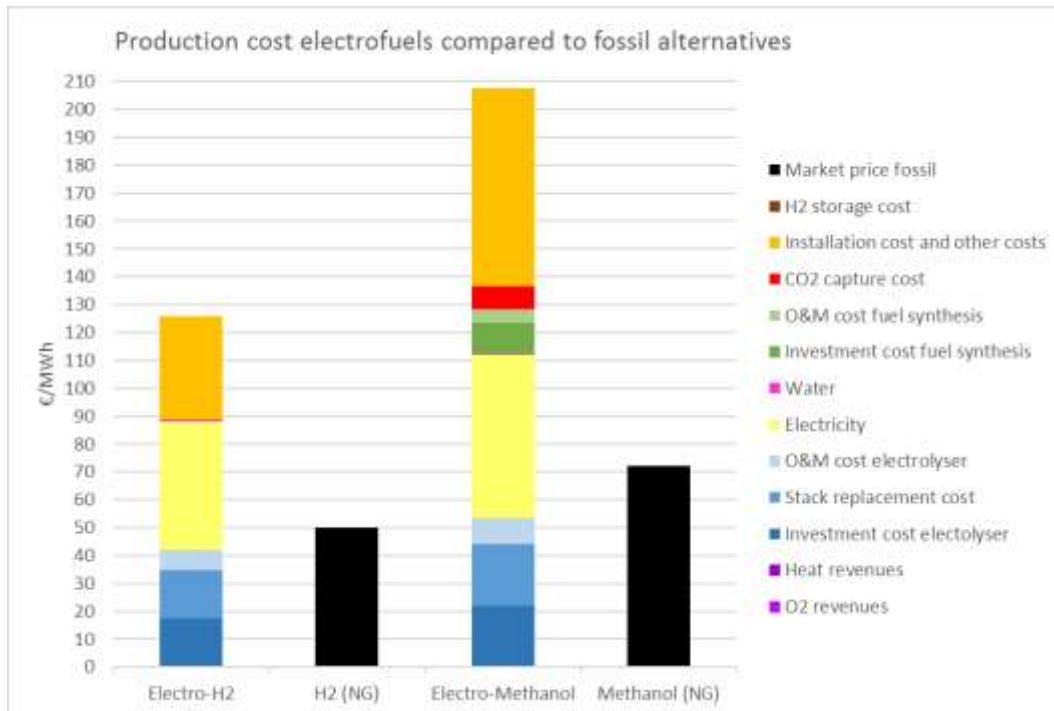


Figure A.2. Production cost for electro-hydrogen and electro-methanol, using base case assumptions for the Preem case, as presented in Table 7, apart from here assuming *higher investment cost electrolyser* (PEM, 1000 €/kW). Fossil alternatives are included for comparison.

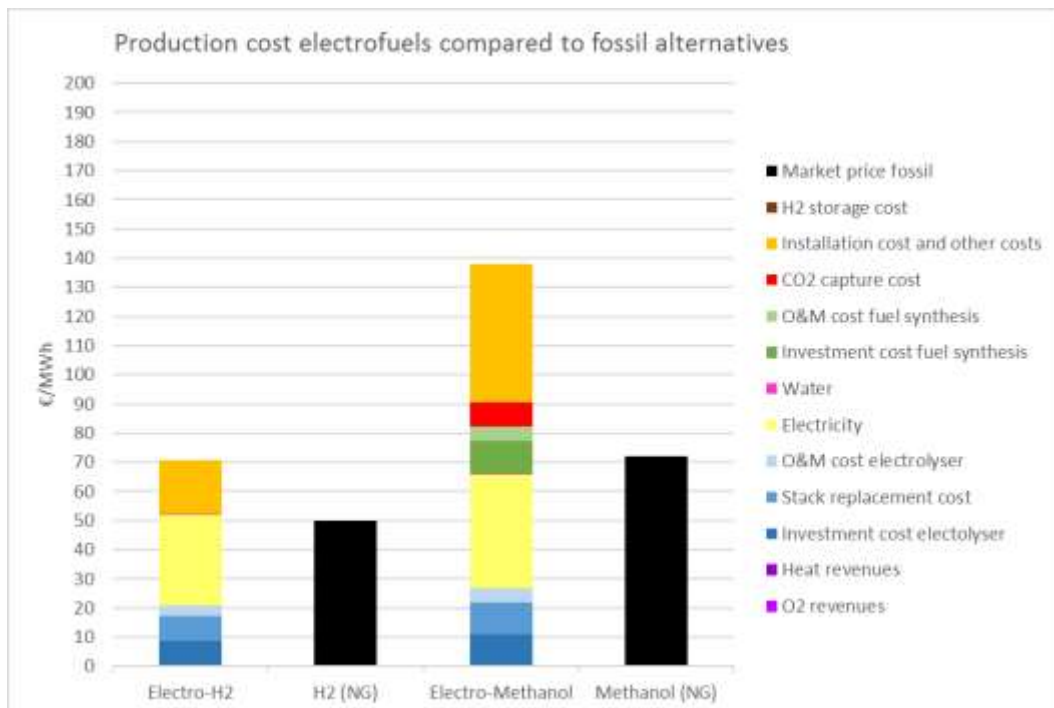


Figure A.3. Production cost for electro-hydrogen and electro-methanol, using base case assumptions for the Preem case, as presented in Table 7, apart from here assuming *lower electricity price* (20 €/MWh_{el}). Fossil alternatives are included for comparison.

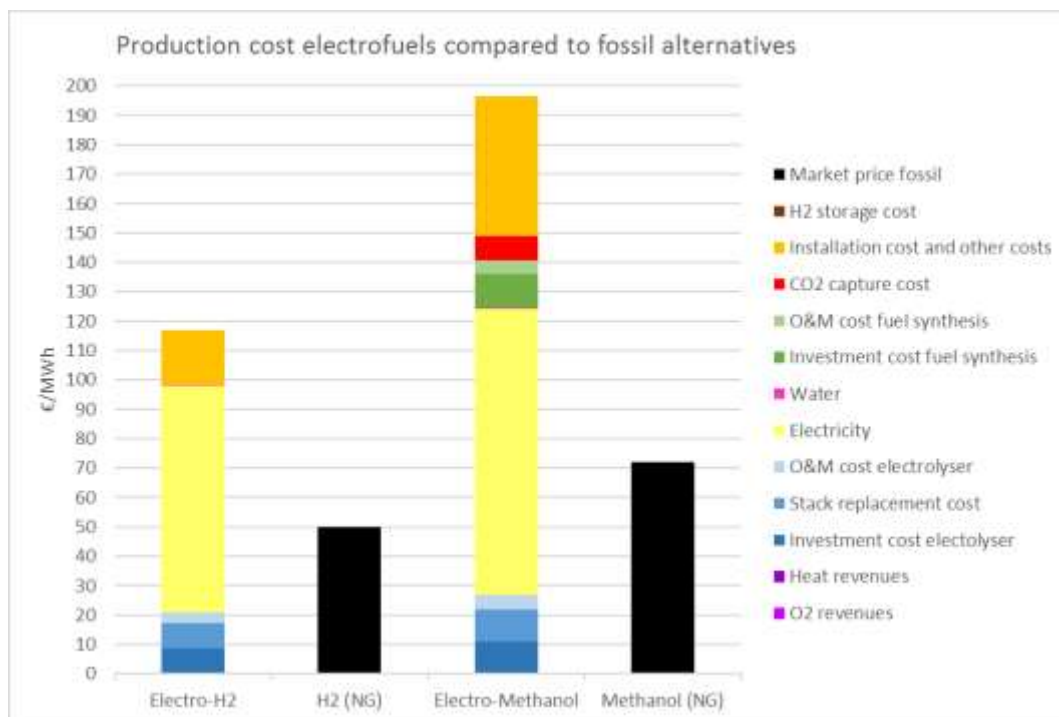


Figure A.4. Production cost for electro-hydrogen and electro-methanol, using base case assumptions for the Preem case, as presented in Table 7, apart from here assuming *higher electricity price (50 €/MWh_{el})*. Fossil alternatives are included for comparison.

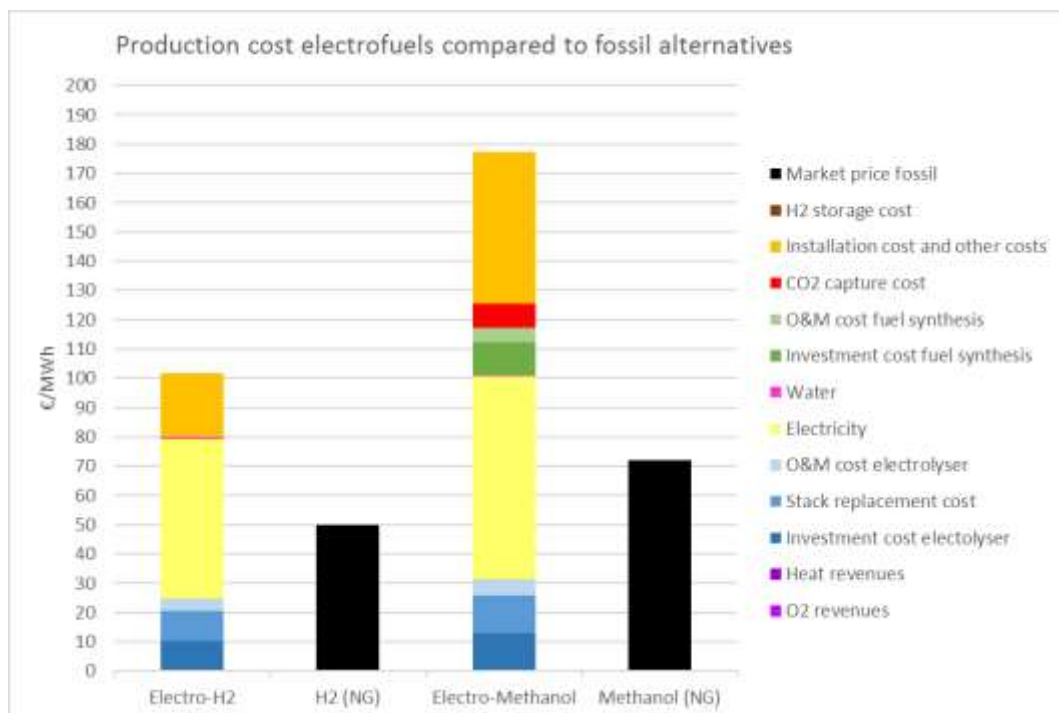


Figure A.5. Production cost for electro-hydrogen and electro-methanol, using base case assumptions for the Preem case, as presented in Table 7, apart from here assuming *lower conversion efficiency for the electrolyser (55%)*. Fossil alternatives are included for comparison.

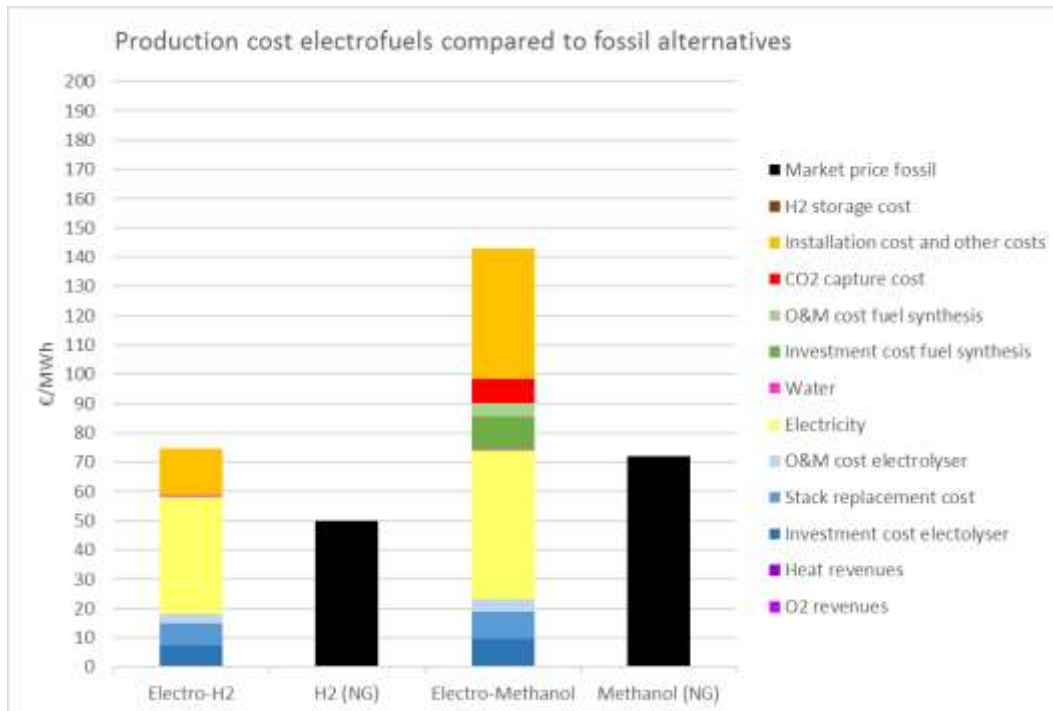


Figure A.6. Production cost for electro-hydrogen and electro-methanol, using base case assumptions for the Preem case, as presented in Table 7, apart from here assuming *higher conversion efficiency for the electrolyser (75%)*. Fossil alternatives are included for comparison.

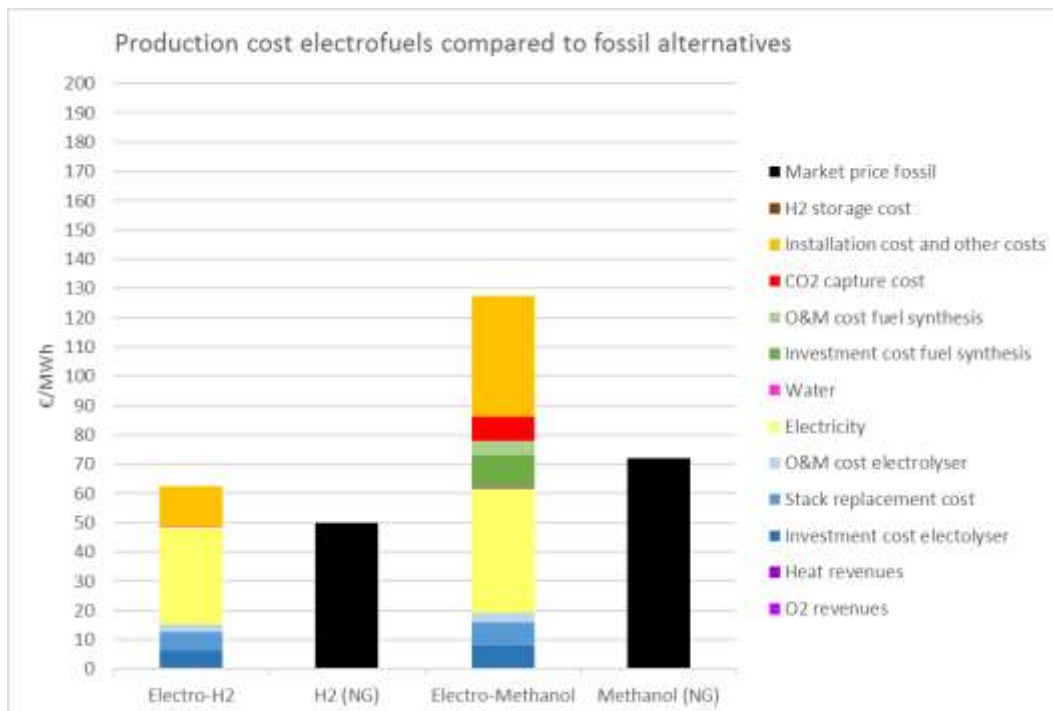


Figure A.7. Production cost for electro-hydrogen and electro-methanol, using base case assumptions for the Preem case, as presented in Table 7, apart from here assuming *ultimate conversion efficiency for the electrolyser (SOEC, 90%)*. Fossil alternatives are included for comparison.

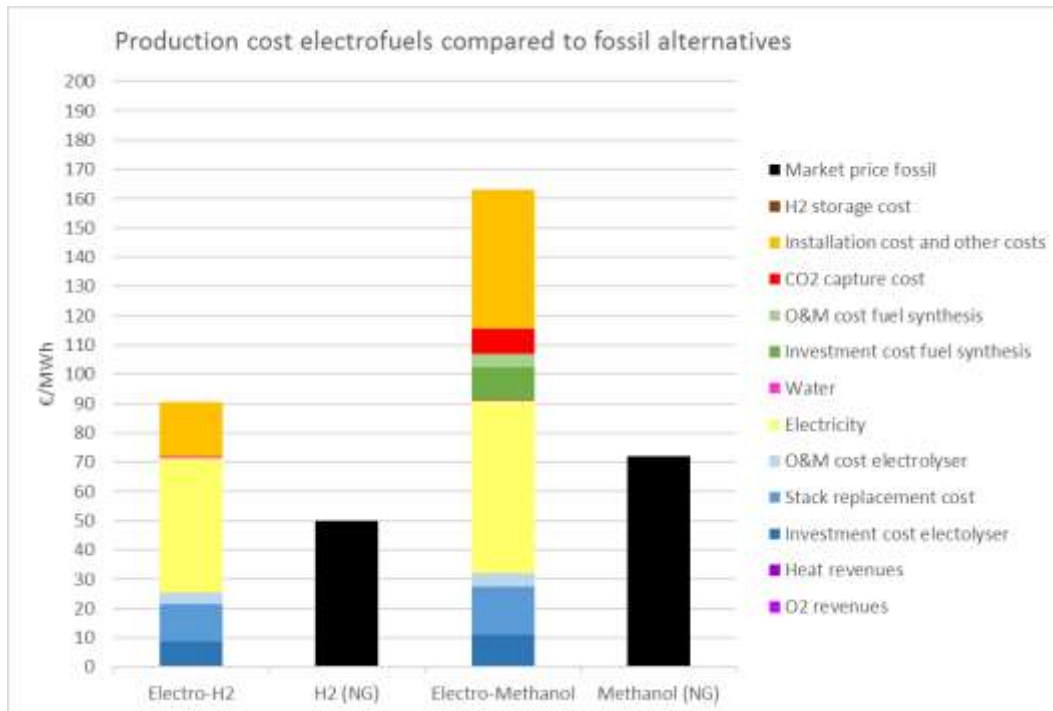


Figure A.8. Production cost for electro-hydrogen and electro-methanol, using base case assumptions for the Preem case, as presented in Table 7, apart from here assuming *lower electrolyser's life time (65,000h)* leading to 3 stack replacements. Fossil alternatives are included for comparison.

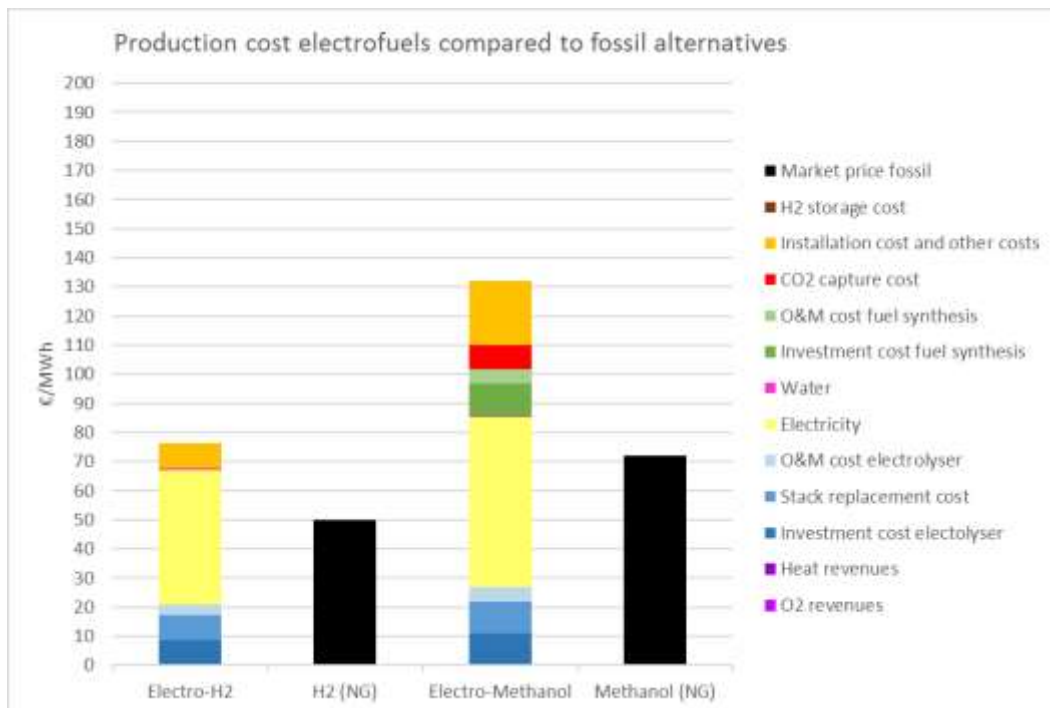


Figure A.9. Production cost for electro-hydrogen and electro-methanol, using base case assumptions for the Preem case, as presented in Table 7, apart from here assuming *lower experience factor for indirect investment costs (a factor of 2)*. Fossil alternatives are included for comparison.

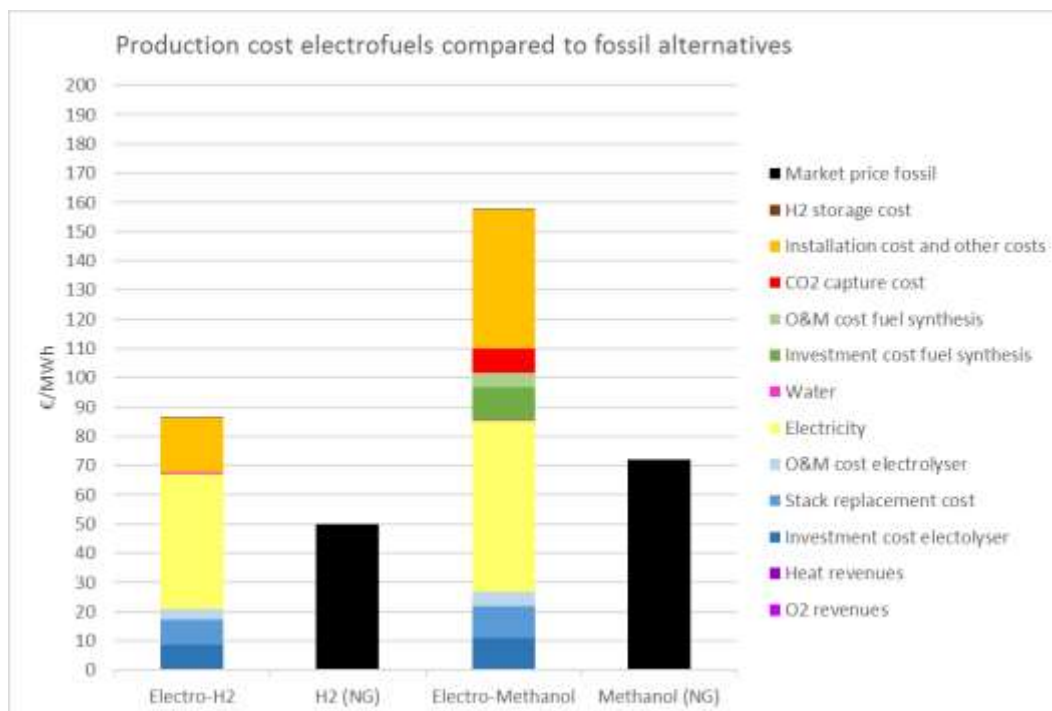


Figure A.10. Production cost for electro-hydrogen and electro-methanol, using base case assumptions for the Preem case, as presented in Table 7, apart from here assuming a need for 10h hydrogen storage at a cost of 1 €/Nm³ (large scale underground storage). Fossil alternatives are included for comparison.

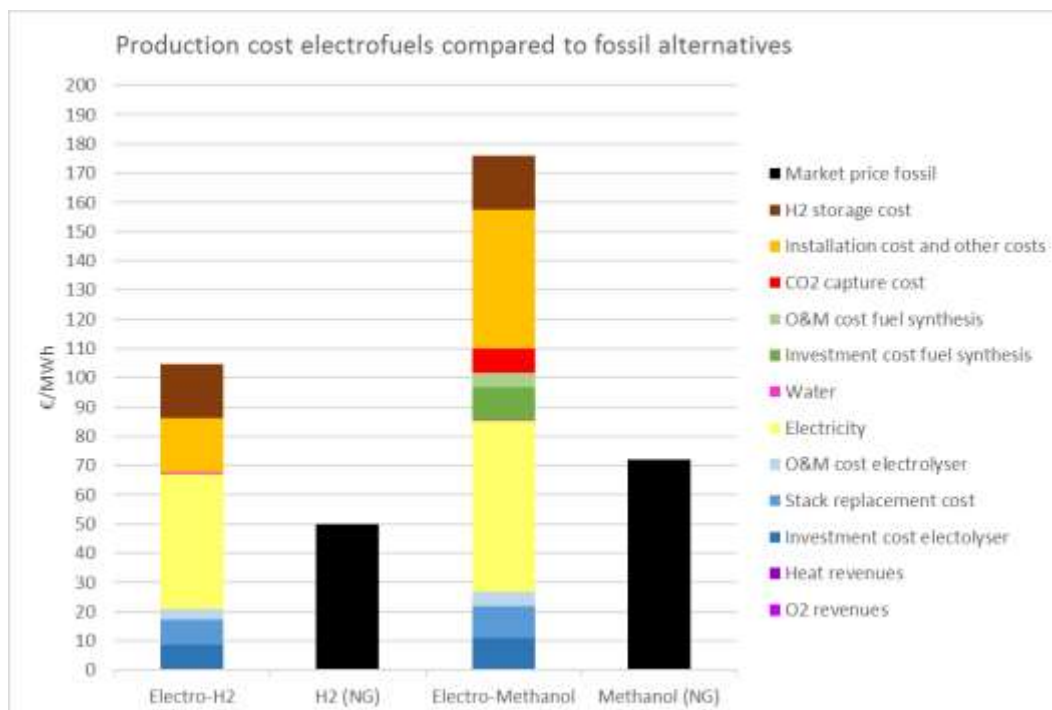


Figure A.11. Production cost for electro-hydrogen and electro-methanol, using base case assumptions for the Preem case, as presented in Table 7, apart from here assuming a need for 10h hydrogen storage at a cost of 46 €/Nm³ (45 bar container). Fossil alternatives are included for comparison.

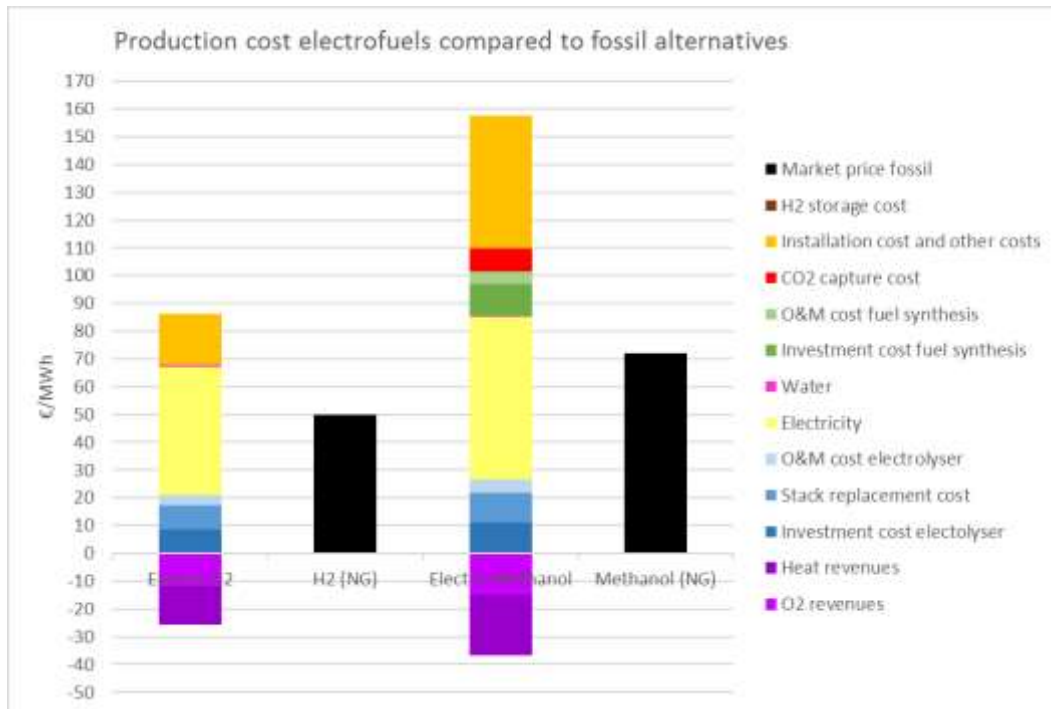


Figure A.12. Production cost for electro-hydrogen and electro-methanol, using base case assumptions for the Preem case, as presented in Table 7, apart from here assuming a market for excess heat and oxygen (30 €/MWh and 50 €/ton respectively). Fossil alternatives are included for comparison. Note that total cost is the presented bar minus the revenue posts, i.e. 61 and 121 €/MWh for the electro-hydrogen and electro-methanol respectively.

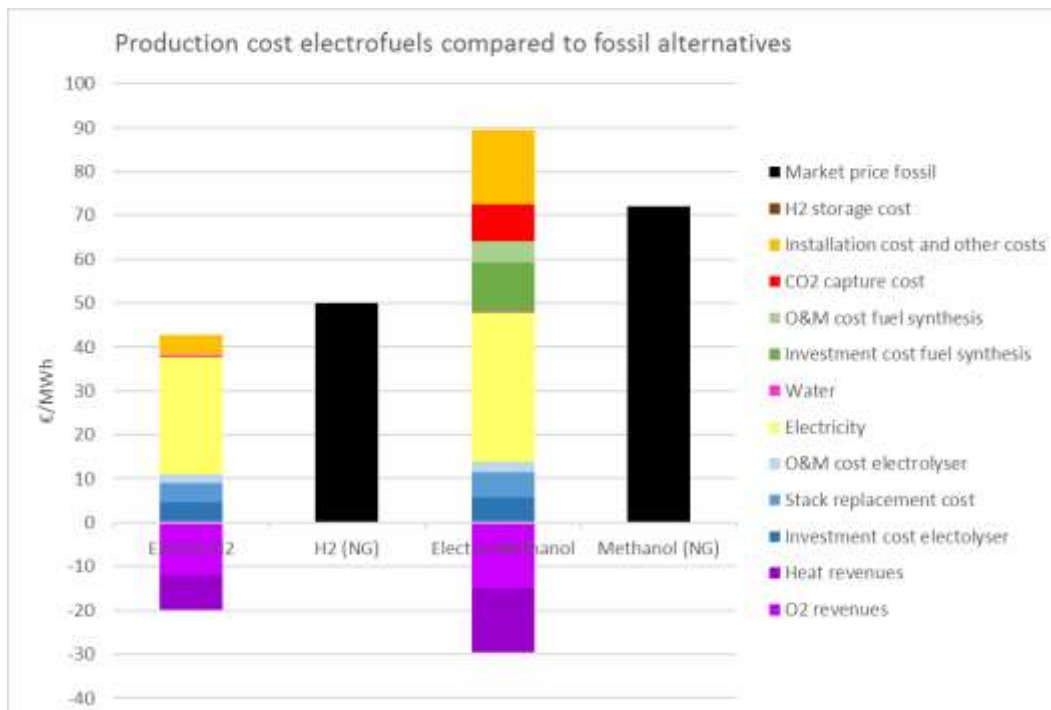


Figure A.13. Production cost for electro-hydrogen and electro-methanol, using base case assumptions for the Preem case, as presented in Table 7, apart from here assuming all optimistic assumptions combined (i.e., 1,3,6,9,12). Fossil alternatives are included for comparison. Note that total cost is the presented bar minus the revenue posts, i.e. 23 and 60 €/MWh for the electro-hydrogen and electro-methanol respectively.

Table A.2. Results comparison of production costs.

	Fuel production cost (€/MWh)	Times more expensive, compared to fossil alternative	More expensive compared to base case (€/MWh)
<i>Electro-hydrogen</i>			
1. lower investment cost electrolyser (potential cost reduction for future alkaline)	70	1.4	–16
2. higher investment cost electrolyser (PEM)	126	2.5	40
3. lower electricity price	71	1.4	–15
4. higher electricity price	117	2.3	31
5. lower conversion efficiency electrolyser	102	2.0	16
6. higher conversion efficiency electrolyser	75	1.5	–11
7. ultimate conversion efficiency electrolyser (SOEC)	62	1.2	–24
8. lower electrolyser's stack life time	91	1.8	5
9. lower experience factor for indirect investment costs	76	1.5	–10
10. assume need for hydrogen storage cost (large scale underground storage)	87	1.7	1
11. assume need for hydrogen storage cost (45 bar container)	105	2.1	19
12. heat and oxygen revenue	61	1.2	–25
13. combining all optimistic assumptions (1,3,6,9,12)	23	0.5	–63
<i>Electro-methanol</i>			
1. lower investment cost electrolyser (potential cost reduction for future alkaline)	137	1.9	–21
2. higher investment cost electrolyser (PEM)	208	2.9	50
3. lower electricity price	138	1.9	–20
4. higher electricity price	197	2.7	39
5. lower conversion efficiency electrolyser	177	2.5	19
6. higher conversion efficiency electrolyser	143	2.0	–15
7. ultimate conversion efficiency electrolyser (SOEC)	127	1.8	–31
8. lower electrolyser's stack life time	163	2.3	5
9. lower experience factor for indirect investment costs	132	1.8	–26
10. assume need for hydrogen storage cost (large scale underground storage)	158	2.2	0
11. assume need for hydrogen storage cost (45 bar container)	176	2.4	18
12. heat and oxygen revenue	121	1.7	–37
13. combining all optimistic assumptions (1,3,6,9,12)	60	0.8	–98

Table A.3. Results cost per avoided CO₂ emission.

	additional cost for the production plant (M€/yr)	Avoided CO ₂ (kton CO ₂ /yr)	Cost per avoided CO ₂ (€/tCO ₂)
<i>Electro-hydrogen</i>			
1. lower investment cost electrolyser (potential cost reduction for future alkaline)	61	762	80
2. higher investment cost electrolyser (PEM)	227	762	298
3. lower electricity price	63	762	82
4. higher electricity price	201	762	264
5. lower conversion efficiency electrolyser	155	762	204
6. higher conversion efficiency electrolyser	74	762	98
7. ultimate conversion efficiency electrolyser (SOEC)	37	762	49
8. lower electrolyser's stack life time	122	762	160
9. lower experience factor for indirect investment costs	79	762	104
10. assume need for hydrogen storage cost (large scale underground storage)	110	762	144
11. assume need for hydrogen storage cost (45 bar container)	164	762	215
12. heat and oxygen revenue	32	762	41
13. combining all optimistic assumptions (1,3,6,9,12)	-82	762	-107
<i>Electro-methanol</i>			
1. lower investment cost electrolyser (potential cost reduction for future alkaline)	5.82	24	242
2. higher investment cost electrolyser (PEM)	12.06	24	501
3. lower electricity price	5.87	24	244
4. higher electricity price	11.07	24	460
5. lower conversion efficiency electrolyser	9.36	24	389
6. higher conversion efficiency electrolyser	6.31	24	262
7. ultimate conversion efficiency electrolyser (SOEC)	4.92	24	204
8. lower electrolyser's stack life time	8.09	24	336
9. lower experience factor for indirect investment costs	5.35	24	222
10. assume need for hydrogen storage cost (large scale underground storage)	7.64	24	317
11. assume need for hydrogen storage cost (45 bar container)	9.24	24	384
12. heat and oxygen revenue	4.32	24	180
13. combining all optimistic assumptions (1,3,6,9,12)	-1.08	24	-45

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