## PUBLICATION

## **Final report**

# **MULTI FILLING STATIONS**

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## PREFACE

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The Swedish Energy Agency is a government agency subordinate to the Ministry of Infrastructure. The Swedish Energy Agency is leading the energy transition into a modern and sustainable, fossil free welfare society and supports research on renewable energy sources, the energy system, and future transportation fuels production and use.

f3 Swedish Knowledge Centre for Renewable Transportation Fuels is a networking organization which focuses on development of environmentally, economically and socially sustainable renewable fuels. The f3 centre is financed jointly by the centre partners and the region of Västra Götaland. Chalmers Industriteknik functions as the host of the f3 organisation (see <a href="https://f3centre.se/en/about-f3">https://f3centre.se/en/about-f3</a>).

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# **EXECUTIVE SUMMARY**

Hydrogen is expected to play an important role in reducing the environmental impacts of the transport sector and is already considered an important component of the future fuel mix in almost all transport modes including road, sea as well as aviation. Within the research project "Multi-filling stations" (funded by the Swedish Energy Agency), different pathways for hydrogen production and distribution are assessed. Through a systematic evaluation of technoeconomic parameters and impact from greenhouse gas (GHG) emissions, the project investigates the feasibility of hydrogen production both in centralized and decentralized systems and by using different production technologies. The overall aim of the project is to enhance adoption of hydrogen production for transport applications and provide a holistic and systematic overview.

In this report, the cost and climate performance of the hydrogen production pathways assessed in the aforementioned project is investigated. More specifically we study the cost for hydrogen at the filling station as well impact on climate change as an indicator for estimating the impact arising from emissions of GHG as well as the overall energy efficiency of the different systems. The scope of the study is "well-to-tank" where the following steps are considered: hydrogen production, distribution, and storage. In total, four alternatives are designed and assessed in this study:

- 1. **Centralized hydrogen production via water electrolysis** and distribution to multi filling stations through dedicated distribution channels (considered as reference case).
- 2. Centralized hydrogen production via steam reforming of bio-methane and distribution to multi filling stations through dedicated distribution channels.
- 3. Decentralized hydrogen production via water electrolysis at multi filling stations.
- 4. **Decentralized hydrogen production via steam reforming of bio-methane** at multi filling stations.

The system boundaries define the boundaries for the system solutions for centralised and decentralised production that are assumed to produce a total of 50 GWh of hydrogen per year. The hydrogen is supplied to end users at filling stations where each filling station either handles 5 or 10 GWh of hydrogen per filling station and year.

In general, it can be concluded that the systems with the smaller capacity are more expensive in terms of cost per kg  $H_2$ , and electrolyser-based systems are cheaper compared to reformer-based systems. In terms of influencers for overall production costs for hydrogen, price for electricity and biogas are the strongest contributors, for electrolyser- and reformer-based production, respectively.

The findings of the study indicate that steam reforming of bio-methane for hydrogen production in a centralized or decentralized facility led to the alternatives with the lowest net emissions of GHG. This is mainly due to the low impact of bio-methane especially when waste and residues are used as feedstocks and when co-products from biogas production can be used to replace fossil alternatives (such as mineral fertilizers).

In accordance with other studies, the carbon intensity of the electricity mix used, especially in the case of the hydrogen production via electrolysis and the possibility to offset the co-products obtained (such as heat or oxygen) can have a strong influence on the results. In the case of the biomethane reforming systems, the carbon intensity of the biogas used in the process would determine the overall environmental performance of hydrogen.

# SAMMANFATTNING

Vätgas förväntas spela en viktig roll för att reducera miljöpåverkan i transportsektorn och anses redan nu vara en viktig komponent i den framtida bränslemixen för nästan alla transportslag inklusive vägtransport, sjöfart och flygtransport. Inom forskningsprojektet "Multitankstationer" (finansierat av Energimyndigheten) bedöms olika tillvägagångssätt för vätgasproduktion och distribution. Genom systematisk utvärdering av teknoekonomiska parametrar och påverkan från utsläpp av växthusgaser så undersöker projektet möjligheten för vätgasproduktion både i centraliserade och decentraliserade system samt genom användning av olika produktionstekniker. Det övergripliga målet med projektet är att förbättra implementeringen av vätgasproduktion för transportapplikationer och att ge en holistisk och systematisk översikt över teknikvalen.

I rapporten undersöks kostnaden och klimatpresentandan för de valda tillvägagångssätten för vätgasproduktion. Mer specifikt studerar vi kostnaden för vätgas vid tankstation för vätgas och påverkan på klimatförändringen som en indikator för att uppskatta påverkan från utsläpp av växthusgaser samt den övergripande energieffektiviteten hos de olika system. Omfattning av studien är "well-to-tank" där följande steg beaktas: vätgasproduktion, distribution och lagring. Totalt utformas och utvärderas fyra alternativ i denna studie:

- 1. **Centraliserad vätgasproduktion via vattenelektrolys** och distribution till multitankstationer genom dedikerade distributionskanaler (betraktas som referensfall)
- 2. **Centraliserad vätgasproduktion via ångreformering av bio-metan** och distribution till multitankstationer genom dedikerade distributionskanaler
- 3. **Decentraliserad vätgasproduktion via vattenelektrolys** och distribution till multitankstationer genom dedikerade distributionskanaler
- 4. **Decentraliserad vätgasproduktion via ångreformering av bio-metan** och distribution till multitankstationer genom dedikerade distributionskanaler

Systemgränserna definierar gränserna för de systemlösningar för centraliserad och decentraliserad produktion som antas producera totalt 50 GWh vätgas per år. Vätgasen levereras till slutanvändare på tankstationer där varje tankstation antingen hanterar 5 eller 10 GWh vätgas per tankstation och år.

Generellt kan man dra slutsatsen att systemen med den mindre kapaciteten är dyrare sett till kostnad per kg H<sub>2</sub>, och att elektrolys baserade system är billigare jämfört med reformer baserade system. Sett till influensers för den totala produktionskostnader för vätgas är priset på el och biogas de starkaste bidragsgivarna, för elektrolys- respektive reformer baserad produktion.

Resultaten av studien tyder på att ångreformering av bio-metan för vätgasproduktion i en centraliserad eller decentraliserad anläggning ledde till alternativen med lägst nettoutsläpp av växthusgaser. Detta beror främst på den låga påverkan av bio-metan, särskilt när avfall och restprodukter används som substrat och när biprodukter från biogasproduktion kan användas för att ersätta fossila alternativ (som mineralgödsel).

I enlighet med andra studier kan kolintensiteten i den använda elmixen, särskilt vid vätgasproduktion via elektrolys och möjligheten att kompensera för de erhållna biprodukterna (som värme eller syre) ha en stark inverkan på resultaten. När det gäller system för reformering av bio-metan, skulle kolintensiteten hos den biogas som används i processen avgöra vätgasens övergripande miljöprestanda.

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# **DEFINITIONS AND ABBREVIATIONS**

Concept	Definition
AEL	Alkaline Water Electrolysis
Biogas	A mixture of methane (CH4), carbon dioxide (CO2) and small quantities of other gases produced by anaerobic digestion of organic matter in an oxygen free environment.
Bio-Methane	A near-pure source of renewable methane produced by "upgrading" biogas (a process that removes any $CO_2$ and other contaminants present in the biogas).
CAPEX	Capital expenditures
CBG	Compressed Bio-Methane
GHG	Greenhouse Gas Emissions
LBG	Liquefied Bio-Methane
LCA	Life Cycle Assesment
OPEX	Operational expenditures
Multi filling station	A filling station that offers more than one renewable and sustainable fuel. In this case renewable hydrogen and bio-methane.
RED	Renewable Energy Directive
PEM	Polymer Electrolyte Membrane Electrolysis
SMR	Steam Methane Reformer
TRL <sup>1</sup>	Technology readiness levels on a scale from 1 to 9 with 9 being the most mature technology

<sup>&</sup>lt;sup>1</sup> <u>https://ec.europa.eu/research/participants/data/ref/h2020/wp/2014\_2015/annexes/h2020-wp1415-annex-g-trl\_en.pdf</u>

## **1** INTRODUCTION

#### 1.1 BACKGROUND

Hydrogen is the simplest molecule of the smallest of our elements. Hydrogen is a gas down to very low temperatures, -253°C (Hydrogen Sweden, n.d.). In relation to its mass, the hydrogen molecule contains a lot of energy and has a calorific value (LHV) of 120 MJ/kg, which is 2.4 times higher than methane (50 MJ/kg), and almost three times higher than diesel (43 MJ/kg). In terms of volume, however, the energy content is lower (3.3 kWh/Nm<sup>3</sup>) and 1 Nm<sup>3</sup> of hydrogen only contains a third of the energy of methane (9.97 kWh/Nm<sup>3</sup>). In combustion of hydrogen and in chemical/thermal processes in fuel cells, predominantly water is formed. Carbon is thus neither included in the fuel nor in its reaction products, and the usage of hydrogen in vehicles does not contribute to carbon dioxide emissions (apart from minor contributions from combustion of lubricants, and because of NOx reduction if Urea injection is used). For these reasons, hydrogen attracts great interest as a fuel in various applications and hydrogen has long been predicted to be a major fuel of the future.

Hydrogen is produced e.g., via steam reforming of methane gas or via electrolysis of water. Hydrogen - like electricity - is an energy carrier rather than an energy source, and the climate performance of hydrogen is to a large extent determined by the performance of the energy source used in its production. However, one should be aware that there are a few studies available (see e.g., (Derwent, et al., 2006)) on hydrogen emissions and their potential climate impact which can change the climate performance of hydrogen.

Current production of hydrogen is mainly concentrated in centralised plants with relatively high production capacity. As a component of coal-based city gas, hydrogen has a long history as an energy carrier in the service of man and has also been tested in pure form in other applications. Today, hydrogen is a well-established industrial gas where the majority goes to fertilizer production (via ammonia), methanol production and as a raw material in refineries. Incorporation of 2 % up to 20 % hydrogen in natural gas grids has been discussed for a few years on the European continent where it is also being investigated to separate the hydrogen gas from the mixture again before end use (IEA, The Future of Hydrogen, 2019). Hydrogen is also a raw material for synthetic methane by reacting hydrogen with carbon dioxide through the Power-to-Gas concept.

Despite the large use of hydrogen in various industrial sectors, the use in transport applications has so far been very limited. According to the IEA (Hydrogen, 2021a), more than 40 000 fuel cell electric vehicles (FCEVs) were on the road globally by the end of June 2021. The statistics for 2020 include: cars (25,930), buses (6,650), and commercial vehicles (3,220) that use hydrogen as fuel in the world today. In addition, there are also over 25,000 industrial trucks in usage. Several manufacturers are active for each segment. There are a small number of established filling stations (around 540) for hydrogen in the world, where Japan has about 140, the USA approx. 65, China around 85, Korea around 15, Germany around 90, around 105 are found in the rest of Europe and the rest are scattered in other parts of the world. According to Hydrogen Sweden (Vätgastanksstationer, n.d.), there are currently five filling stations in Sweden, but the numbers are expected to grow rapidly in the upcoming years as several dozens more are currently in different stages of planning. The theoretical potential for future use of hydrogen in road transport is very large. Each type of

road transport can be technically propelled by hydrogen, either directly with the help of fuel cells or via hydrogen-based fuels in internal combustion engines.

Hydrogen filling stations are usually not yet profitable due to high investment, operating and maintenance costs and so far, small volumes of hydrogen sales. There are major economies of scale in the establishment of hydrogen filling stations, but this requires a high demand for hydrogen (IEA, The Future of Hydrogen, 2019).

According to the IEA (The Future of Hydrogen, 2019) the distribution of hydrogen to service stations may require more time and labour than is the case with conventional transport fuels. Hydrogen distribution can also be a bottleneck if a centralised plant for production is far away from the filling station. This is because it is relatively expensive to lay gas pipelines or transport gas in bottles when demand is low. There is a possibility to reduce costs by switching to more advanced distribution alternatives (e.g., very high pressure or liquid hydrogen) or by scaling up the manufacture of station components.

Instead of producing hydrogen in large-scale plants and then transporting it in dedicated systems (gas cylinders or possible gas pipelines for hydrogen only), there is an opportunity to produce hydrogen at the site of its use. Production can either take place through electrolysis, where water is a raw material and electricity is an energy source, or through reforming of methane, which consists of already upgraded biogas. In the latter case, an already established distribution system for upgraded biogas is used and part of this is led to a small-scale reformer that converts methane to hydrogen and carbon dioxide.

## 1.2 PROJECT OBJECTIVES

This research project aims to increase the knowledge of the conditions for providing a future transport system with environmentally, economically, and socially sustainable renewable fuels. The project produces information on which alternative could be the most sustainable to create a new concept for hydrogen filling stations.

The project aims to investigate the possibilities of using existing infrastructure for one fuel (upgraded biogas) to enable extended establishment of another (hydrogen). The project also includes a comparison of the conditions for different types of technology solutions, for production of hydrogen, to achieve increased access to hydrogen as a fuel for vehicles.

Four different system solutions for making hydrogen available are compared, all with the same aim of establishing a multi filling station for LBG/CBG and hydrogen as fuels. For all solutions LBG/CBG are supplied to the station through conventional channels of distribution. The four system solutions are:

- 1. Centralised hydrogen production through electrolysis with subsequent distribution via dedicated channels to the multi filling station.
- 2. Centralised hydrogen production though SMR of bio-methane at a biogas production and up-grading facility with subsequent distribution of hydrogen through dedicated channels to the multi filling station.
- 3. Decentralised hydrogen production through electrolysis at the multi filling station.

4. Decentralised hydrogen production though SMR of bio-methane at the multi filling station. *Alternative 1* has been used as the reference case in this study.

## **1.3 SYSTEM DELIMITATIONS**

The biogas system (LBG/CBG) is already considered mature and established as a fuel as well as in terms of technology and infrastructure, so the biogas system is not evaluated from a technology maturity perspective. It is also assumed that a filling station for bio-methane is already in place and that only the complementary installations needed for the establishment of a hydrogen infrastructure are included in this report. A Multi-filling station becomes more of a possibility when using existing infrastructure to co-establish a hydrogen filling station at a bio-methane filling station.

In terms of costs, the technologies chosen to be used in the case studies have been chosen based on the assumption that they are mature technologies for today's time perspectives. Cost estimates in this study are therefore assumed to represent mature costs i.e., the case when these technologies have reached a commercial position on the market. Thus, the hydrogen pathways are compared for the situation when they are commercial with today's price level, which is considered a fair comparison base. Today's price level is assumed to be costs that represents the price that an organization likely will have to pay for the equipment, material etc. at today's market conditions.

# 2 OVERALL APPROACH

This analysis includes: 1) System boundaries, 2) technological maturity, 3) costs and 4) Life Cycle Assessment. The system boundaries and the technological maturity of the system solutions act as a background for the costs and Life Cycle Assessment. The cost assessment covers cost for hydrogen production, distribution and filling station which are synthesized and the Life Cycle Assessment covers the environmental impact.

## 2.1 SYSTEM BOUNDARIES

The system boundaries define the boundaries for the system solutions for centralised and decentralised production that are assumed to produce a total of 50 GWh of hydrogen per year. The hydrogen is supplied to end users at filling stations where each filling station either handles 5 or 10 GWh of hydrogen per filling station and year.

Production capacity of the central solution is thus 50 GWh  $H_2$ /year and the production capacity of each installation for the decentralised solution is 5-10 GWh  $H_2$ /year. The production capacity for the central solutions corresponds to 5-10 sites for filling stations and the production capacity for the decentralised solutions is equivalent to the capacity of each filling station. The difference between the two systems is the chosen production technologies (electrolyser/reformer) while remaining subsystems are equivalent. The system solutions are shown in Table 1, explained shortly above and explained further in chapter 3.

The chosen production volume of 50 GWh  $H_2$ /year corresponds approximately to a 10 MW<sub>el</sub> centralised electrolyser, being well in-line with the scale of existing and planned units (see chapter 4.1.1).

System Solution and pathway		Transportation form (H <sub>2</sub> carrier)	Production volume (GWh or tons H <sub>2</sub> /year)		Production technology	Transpor- tation form for H <sub>2</sub>	Filling station (GWh or tons H <sub>2</sub> /year)	
Cer	1a	Pipeline (H <sub>2</sub> O)	50	1 500	Electrolysis	Road	5	150
ntralised	1b		50	1 500		transport	10	300
	2a	Production at site (CH <sub>4</sub> )	50	1 500	SMR	Road transport	5	150
	2b		50	1 500			10	300
De	<b>3</b> a	Pipeline (H <sub>2</sub> O)	5	150	Electrolysis	Production at	5	150
ecentr	3b		10	300		site	10	300
alisec	4a	Pipeline or road	5	150	SMR	Production at	5	150
ä	4b	transport (CH <sub>4</sub> )	10	300		site	10	300

Table 1	l. System	solutions t	hat are	divided i	into four	central a	and four	decentralised	pathways
I abit	li Dystem	solutions t	nat al c	uiviucu	mio ioui	contrar t	inu ioui	uccenti anscu	painways

## 2.2 TECHNOLOGICAL MATURITY

The degree of technological maturity is evaluated because only mature technologies available today is used in this study. The evaluation is done through literature studies and dialogue with suppliers and other stakeholders. This is done through:

- identifying the specified Technology Readiness Level (TRL) in the literature
- identifying suppliers and their reference cases of who supplies technologies suitable for the four different system solutions defined in chapter 3. A supplier that has reference cases for its technology is assumed to have an TRL of 9 when the technology is applied in its final form, under real-world conditions and has been applied into the market.

The choice of the appropriate scale, storage needs, type of distribution systems and capacity of the technical systems for the four system solutions is based on the identified technically mature solutions available in chapter 4.

## 2.3 REVIEW OF COSTS

Hydrogen production costs, cost of storage, distribution, and the filling station have been evaluated for each production pathway. The cost estimates are based on a literature review of scientific papers and reports covering production of hydrogen and distribution/ infrastructure. The existing cost estimates have been updated with new information from suppliers when needed. Each part of the cost structure that is similar for the different cases has been evaluated similarly or with similar principles, for example the filling stations.

The updates have been the cost of small-scale steam methane reforming, distribution of hydrogen and hydrogen filling stations that have been adjusted to reflect Swedish conditions and chosen system solutions. See chapter 5 for more details. For small scale reformers data has been discussed with, and collected from, Metacon (E-mail conversation, 2021), see 5.1.2. Data for refuelling stations and truck loading terminals were primarily based on data derived from the HDSAM and HDRSAM models developed by Argonne National Laboratory (Hydrogen Delivery Scenario Analysis Model, n.d.). See sections 0 and 5.3 for details on the models and any adjustments/additions made in the present work.

In general, we have tried to use studies that include assessment in a uniform way, using homogeneous assumptions, as far as possible. Using separate studies for different technical options can lead to larger difficulties in in obtaining a relevant comparison, due to the use of different assumptions and system boundaries.

An overview of the initial literature review covering cost estimates for production, storage, distribution, and filling station for hydrogen is presented in section 5. The cost estimates covered in the identified publications are indicated.

Detailed information on the background material from selected literature and suppliers used to calculate production, distribution, and infrastructure costs for this study is presented in Appendix A.

## 2.4 SYNTHESIS OF COSTS

The cost calculations, described here as well as in chapter 5, aim to present the costs for building, maintaining, producing and making hydrogen available to end consumers at hydrogen filling stations at an already existing bio-methane filling station.

The basis for the cost calculations has been to find a fair level of costs that represents the price that an organisation likely will have to pay for the equipment, material etc at today's market conditions. The economic assessment performed in this study calculates the price for hydrogen gas in SEK/kg to the end customer excluding costs such as profits, marketing, and overhead costs. The operational expenditures (OPEX) and capital expenditures (CAPEX), has been calculated and the required annual payment for an annuity has been based on fixed periodic payments and a constant interest rate.

The interest rate is set to 6 % which is in line with other economic studies (Börjesson, et al. 2016; Gustafsson, Cruz, Svensson, & Karlsson, 2020)) The depreciation period for investments in this study is set to 15 years. Its also the estimated life span suggested by the Swedish Environmental Protection Agency (EPA) when calculating the need for investment subsidies within the current Swedish climate investment programme (Naturvårdsverket, n.d.).

Unexpected investment costs and indirect costs such as site preparation and engineering for the installations is assumed where 10 % of the investment cost each is added to the costs. Site preparation, engineering is assumed to be a cost that the contractor adds to the price. It is important to note that the costs presented do not include indirect costs for the product ( $H_2$ ) such as permits, administration, sales and marketing. Business margins is also not included which often is added to the price for the end customer.

Price levels will vary and develop with market conditions, purchasing power, as well as technological and other developments. Therefore, any of the costs being presented in this study must be seen as a best attempt to present a likely cost level as of today's mature technologies.

#### 2.4.1 Sensitivity analysis

To be able to better understand how changes and a development of different costs will affect the cost levels, sensitivity analysis has been conducted for a selected number of parameters. These specific parameters have been chosen based on their total importance in relation to hydrogen production costs and based on discussions with stakeholders. For each parameter under study in this section, the cost level of that specific parameter has been varied in a chosen range and the results are presented in *chapter 6.4*. There, a more detailed description and analysis of each analysis can also be found.

The parameters chosen to be varied are:

- Investments such as costs for components and especially costs for electrolyser and reformers respectively
- Price of electricity
- Price of biogas
- Utilisation rate of the total system

- Transport distance
- Costs for reformer
- Utilisation rate of the total system
- Utilisation rate of the hydrogen filling station. Including production variation for decentralised production. For the centralised production, the price of hydrogen has been kept at a constant level.

### 2.5 LIFE CYCLE ASSESMENT (LCA)

The environmental impact from the production and distribution of hydrogen to the refueling stations, is evaluated from a life cycle perspective and by considering all key activities related to hydrogen production, distribution, and storage. In this work, the focus of the assessment has been on climate change and the associated performance of different hydrogen production systems in terms of greenhouse gas (GHG) emissions. Moreover, an energy efficiency indicator has been calculated. A comparative assessment is performed estimating the potential savings (climate and energy benefits) of the different alternatives in relation to a refence case (case 1, as defined above).

Detained information on the methods used, specific assumptions and methodological decisions in relation to the product system under evaluation are presented in Section 7.1 and section 7.2.

The functional unit considered throughout this work is **1 MJ of compressed gas (hydrogen)** available at the filling station.

# **3 SYSTEM BOUNDARIES**

We explore two cases for the production, distribution and supply of hydrogen to fuelling stations. The production of hydrogen either takes place at a centralised production facility to be subsequently transported by road to the hydrogen filling station or is occurring directly at the hydrogen filling station. The production of hydrogen takes place either via electrolysis of water or steam reforming of bio-methane.

Central and decentralised production is assumed to have a production capacity of 50 GWh  $H_2$ /year in the different system solutions which corresponds to 5-10 filling stations with the capacity of 5-10 GWh  $H_2$ /year. The difference between the two systems is the chosen production technologies (electrolyser/reformer) while remaining subsystems are equivalent.

### 3.1 CENTRALISED PRODUCTION

Hydrogen is produced through electrolysis of water or steam methane reforming of bio-methane. the hydrogen gas is transported in a local gas pipeline from the low-pressure storage to the compressor station that is used to increase the pressure of the hydrogen gas to selected working pressure for the mobile gas storage units that are used to transport the hydrogen in compressed form to the filling station.

Centralised electrolyser uses electricity and water to produce hydrogen gas, oxygen gas and residual heat. It is assumed that there is no use for the oxygen gas which is generated while the residual heat is assumed to be able to be fed into a nearby district heating network. The system boundaries are shown in Figure 1.



Figure 1. Centralised electrolysis. The dashed line indicates the system boundaries. The boxes are divided into three sub-steps that together are the studied system. The sub-steps are Production, Distribution and Hydrogen filling station.

Centralised steam methane reforming of bio-methane uses electricity, water and bio-methane to produce hydrogen gas, carbon dioxide gas and residual heat. It is assumed that there is no use for the carbon dioxide gas that is generated in the process, while the residual heat is assumed to be used in the bio-methane production process. The system boundaries are shown in Figure 2.



Figure 2. Centralised reformer. The dashed line indicates the system boundaries. The boxes are divided into three sub-steps that together are the studied system. The sub-steps are Production, Distribution and Hydrogen filling station.

#### 3.2 DECENTRALISED PRODUCTION

Decentralised electrolyser uses electricity and water to produce hydrogen gas, oxygen gas and residual heat. It is assumed that there is no use for the oxygen gas and the residual heat that are released to the environment. The system boundaries are shown in Figure 3.



Figure 3. Decentralised Electrolysis. The dashed line indicates the system boundaries. The boxes are divided into two sub-steps that together are the studied system. The sub-steps are Production and Hydrogen filling station.

For decentralised steam bio-methane reformer electricity, water and bio-methane are used to produce hydrogen gas, carbon dioxide gas and residual heat. It is assumed that there is no use for the carbon dioxide gas and the residual heat which are released to the environment. The bio-methane is assumed to be transported to the filling station in liquid form on a tank truck or in compressed form by gas pipeline or by truck in containers. The system boundaries are shown in Figure 4.



Figure 4. Decentralised Reformer. The dashed line indicates the system boundaries. The boxes are divi-ded into two sub-steps that together are the studied system. The sub-steps are Production and Hydrogen filling station.

# 4 TECHNOLOGY REVIEW AND CHOICE

The present chapter gives an overview of the different technology options for the above defined pathways. The technological maturity of the different options is presented, and the choice of technology adopted for the present study motivated.

## 4.1 HYDROGEN PRODUCTION

This section gives an overview of two technologies for producing hydrogen. Section 4.1.1 describes water electrolysis and section 4.1.2describes methane reforming.

### 4.1.1 Water electrolysis

Hydrogen can be produced through electrolysis of water in an electrolyser. This process uses electric power (and sometimes heat) to electrochemically split water into hydrogen and oxygen. Electrolysis for hydrogen production is a rapidly developing technology, currently achieving widespread attention from policy makers, technology developers, industrial consumers, vehicle manufacturers and the public. The anticipated increase in installed capacity over the coming decade is huge. For example, the hydrogen strategy of the European Commission targets 6 GW electrolyser capacity within the union by 2024 and a 40 GW capacity by 2030, a significant increase from current capacity which is below 1 GW (European Commission, 2020). At a global scale, the IEA's Sustainable development scenario implies a more than 20-fold growth in global low-carbon hydrogen production, rising from 0.36 Mt/year in 2019 to 7.92 Mt/year in 2030 (from 2.6 GW<sub>el</sub> to 60 GW<sub>el</sub>, assuming 80 % capacity utilisation and a 65 % LHV efficiency of the electrolyser) (IEA, 2021a).

The scale-up in total capacity will be aligned with a significant scale-up in the capacity of individual electrolyser plants. According to the IEA's hydrogen project database (IEA, 2021b) the largest operational (single stack) electrolyser unit is a 10 MW<sub>el</sub> installation commissioned in 2019 in Fukushima, Japan and used to produce hydrogen for use in chemical industry. However, the EU hydrogen strategy calls for the commissioning of 100 MW<sub>el</sub> units by 2024 (European Commission, 2020) and several projects in the hundreds of MW range have been announced for completion before 2025 (IEA, 2021b). A hydrogen production capacity of 50 GWh/year corresponds to an electrolyser stack power rating of 9 MW<sub>el</sub> assuming a 65 % LHV efficiency of the electrolyser. This is well in-line with existing and planned units in present time and considered reasonable within the timeframe of this project.

Among existing and developing electrolysis projects, three main electrolyser technologies can be distinguished: Alkaline, Proton-exchange membrane (below: PEM) and solid-oxide electrolyser cells (below: SOEC) (IEA, 2021b). Alkaline and PEM systems are commercially available and considered TRL 9 at the system sizes investigated in this work. SOEC is the least developed of the three and is distinguished by having a significantly lower power demand than the other techno-

logies, at the cost of a significant high temperature heat demand<sup>2</sup>. Consequently, the envisioned use of the SOEC is (mainly) in configurations where a high temperature heat source is available – for example in electrofuel production or at industrial sites. Because of the heat demand and the low technological maturity, SOEC was not deemed feasible for the system solutions considered in this work and is not discussed further. SOEC could however become an option in the future.

In contrast to SOEC, alkaline and PEM electrolysers are low-temperature technologies operating at cell temperatures of about 20-80 °C, and typically towards the higher end of that range (Shiva Kumar & Himabindu, 2021; Pilenga & Tsdotridis, 2018; Fuller & Harb, 2018). At these temperatures, heat generation at the electrodes is sufficient for overcoming the heat demand of the electrolysis reaction and no external heat supply is necessary, i.e., all the required energy is supplied as electricity and cooling is necessary to maintain cell temperatures (the cooling demand is roughly 20 % of the power input to the electrolyser stack) (Ni, Leung, & Leung, 2008).

The alkaline technology is (currently) more efficient, more mature and has a lower CAPEX than the PEM technology (see below and section 5.1.1). Important advantages of the PEM technology include higher current densities (allowing for smaller units) and better dynamic properties, including faster response times and a wider part load range (Shiva Kumar & Himabindu, 2021). Both electrolyser types are used at existing hydrogen refuelling stations (IEA, 2021b; NEL Hydrogen, 2020; NEL Hydrogen, 2018; H2 Logic, 2017). In this work, electricity supply from the power grid was assumed in the base case and the electrolyser and storage was dimensioned to allow high capacity-utilisation of the electrolyser. This limits the importance of the good dynamic properties of the PEM technology and the alkaline technology was selected for the system solutions analysed in this report, because of its higher efficiency and lower CAPEX.

Technical aspects of alkaline and PEM electrolysers are discussed below, and important parameters for alkaline electrolysers used in the present work are summarised in Table 2. Investment cost data for alkaline electrolysers is discussed in section 5.1.1.

	Value	Unit	Reference	Comment
Stack efficiency	68	%	(Proost, 2019)	Based on H2 LHV
System efficiency	62	%	(Proost, 2019)	Based on H2 LHV. Includes peripheral equipment but no cooling system
Cooling demand	31.8	MJ/kg H <sub>2</sub>	(Tiktak, 2019)	18 % of stack power demand
Delivery pressure	15	Bar (a)	(Proost, 2019)	

 Table 2. Summary of data used for techno-economic evaluation of electrolysers. A detailed description is given in the text below.

<sup>&</sup>lt;sup>2</sup> The energy demand of the electrolysis reaction is  $\Delta H = \Delta G + T\Delta S$ . The electricity demand of the electrolysis reaction is given by the change in Gibbs free energy (237.2 kJ/mol H<sub>2</sub> at standard conditions), while the heat demand is given by the term T $\Delta S$  (48.6 kJ/mol H<sub>2</sub>). At increasing temperatures,  $\Delta G$  decreases while T $\Delta S$  increases. Consequently, the electricity consumption of the electrolysis cell can be decreased at the expense of increasing heat demand by operating at higher temperatures. At low temperatures, heat losses at the electrodes are more than sufficient to overcome the heat demand of the reaction.

#### Stack and system efficiency

Efficiency numbers<sup>3</sup> (LHV hydrogen output per electrolyser power input) are generally in the 60– 65 % range for alkaline and PEM electrolysers, with alkaline towards the high end of the interval (even reaching 70 % according to some claims) and PEM towards the lower end of the interval. The International Energy Agency (2021b) keeps a hydrogen project database containing information on announced as well as existing projects. According to this data most installed electrolysers have efficiencies at about 60 % both for the alkaline and the PEM technology. However, the IEA estimates current state-of-the-art (SOA) for alkaline units to be 63–70 % with a potential of reaching 65–71 % by 2030, and PEM SOA to be 56–60 % with a potential for reaching 63–68 % by 2030 (IEA, The Future of Hydrogen, 2019). This is in line with SOA numbers given by FCH JU<sup>4</sup> for the alkaline technology: 65 % in 2017 and an estimated 69 % in 2030, and for the PEM technology: 57 % in 2017, increasing to 67 % by 2030 (Fuel Cells and Hydrogen Joint Undertaking, n.d.). Data from electrolyser manufacturer Nel Hydrogen suggest a rather wide efficiency range for their alkaline units (62–72 %) while the PEM units are quoted at 60 % (NEL Hydrogen, 2020).

In general, the cited sources do not clearly distinguish between stack efficiency (i.e., efficiency of the actual electrolyser stack) and system efficiency (efficiency of the electrolyser plant including e.g., gas purification and analysis, circulation pumps, transformers etc.), and give only one of the two values. The assessment in (Proost, 2019) is based on manufacturer data and clearly specifies stack and system efficiencies for alkaline electrolysers at 68 and 62 %, respectively, based on the LHV. These values are in line with the numbers discussed above and were used in the present work to model alkaline electrolysers. Note that the system efficiency excludes the electrolyser cooling system.

#### System cooling

A low temperature electrolyser cell has a significant cooling demand and in alkaline electrolysers the cell temperature is often maintained by cooling of the liquid electrolyte which is circulated through the cell (Pilenga & Tsdotridis, 2018). Assuming a stack LHV efficiency of 68 %, about 20 % of the power supplied at the stack is lost as heat (a 68 % LHV efficiency corresponds to an HHV efficiency of 80 %). Assuming a cell temperature of 80 °C and accounting for preheating of feedwater, losses to the environment, and water vapor leaving with the produced gases (oxygen and hydrogen), about 90 % of the heat loss is delivered to the electrolyser cooling system (Tiktak, 2019). This corresponds to about 18 % of the stack power input, or about 16.5 % of the system power input (at 62 % system efficiency as discussed above).

<sup>&</sup>lt;sup>3</sup> Depending on the source, this can be either stack efficiency (hydrogen production related to power input to the electrolyser stack) or system efficiency (hydrogen production related to the power input to the electrolyser system, i.e., including auxiliary equipment). System efficiency is generally a few percentage-points lower than the stack efficiency.

<sup>&</sup>lt;sup>4</sup> Fuel Cells and Hydrogen Joint Undertaking (<u>https://www.fch.europa.eu/</u>) is a public private partnership supporting research, technological development and demonstration (RTD) activities in fuel cell and hydrogen energy technologies in Europe. Its members are the European Commission, industrial actors represented by Hydrogen Europe and researchers represented by Hydrogen Europe Research.

In the present work, it was assumed that the electrolyser is cooled either using a dry cooler system (decentralised production) or free cooling from water (centralised production). The additional power demands for pumps and fans were assumed to be negligible.

#### 4.1.2 Methane reforming

Methane can be converted to hydrogen through Steam Methane Reforming (SMR). Today, approximately 96% of global hydrogen production is produced by SMR from fossil resources such as predominantly natural gas, but also coal, oil, and derivatives thereof. Many types of chemical synthesis processes with a fossil base, use synthesis gas obtained by SMR as feedstock (Pham Minh, et al., 2018). SMR of natural gas at petroleum refineries is the dominant pathway for hydrogen production for the chemical process industry. Product areas where hydrogen is being consumed include the production of mineral fertilizer (through the production of ammonia), methanol production and in the cryogenics sector (Elshout, 2010). Within the petrochemical industry plants for SMR of natural gas has been developed according to economy of scale during the last decades and plants employing the latest version of the technology can reach sizes of 56 000 m<sup>3</sup> of hydrogen per hour and above (Air Liquide, 2021a).

There are several other reforming techniques that can be used to produce hydrogen from methane. Dry reforming of methane (DRM) relates to the reaction between  $CH_4$  and  $CO_2$  to form CO and  $H_2$  without the presence of steam (Pham Minh, et al, 2018). For this type of process, solid carbon and water are generated primarily at temperatures below 600°C. For good conversion of the reactants and high selectivity towards production of CO and  $H_2$ , the DRM process operates above 850°C. Tri-reforming of methane (TRM) also includes oxygen in the reactant mixture, thus making this suitable for landfill gas (LFG) as feedstock. Also, this technique requires temperatures above 800°C to function for the purpose of syngas production (Pham Minh, o.a., 2018). Autothermal reforming (ATR) is another option where oxygen is present in the reaction mixture. Here the methane is partially oxidized, and the outlet temperature and pressure can be up to 1000°C and 100 bar, respectively. While SMR only uses oxygen as an external oxidizer to combust fuel for heat-production, the ATR-process directly uses oxygen as combustion agent within the process itself. It is easier to vary the syngas outlet ratio of H<sub>2</sub>:CO from an ATR-process than from a SMR-process (Haldor Topsoe, 2021) The TRL for DRM, TRM and ATR is 8-9, 6-7, and 9, respectively (Albrecht, et al., 2015).

Biogenic resources such as biogas, can be valorised to produce green hydrogen through SMR. Biogas is produced by fermentation of wastes, residues, and various forms of biomass by a microbiologic consortium producing a mixture of CH<sub>4</sub> and CO<sub>2</sub>, usually around 55-65 and 35-45%, respectively. The raw biogas can be converted directly in a SMR-process, but the potential drawbacks are e.g. lower overall efficiency and higher level of contaminants to account for compared to if the SMR is employed to biogas already upgraded to bio-methane (+97% CH<sub>4</sub>). Another potential drawback is that additional measures may have to be taken to ensure high hydrogen quality when biogas or bio-methane is used as feedstock. According to Albrecht et al. (Study on hydrogen from renewable resources in the EU Final Report, 2015) the TRL is currently 9 for SMR of upgraded biogas and between 8 and 9 for steam reforming of raw biogas.

Fossil natural gas may contain several impurities, such as hydrocarbons, water, carbon dioxide, hydrogen sulfide etc. Bio-methane in Sweden consists of 97  $\% \pm 1\%$  of methane and may contain va-

rious levels of carbon dioxide, carbon monoxide, nitrogen, oxygen, and hydrogen sulfides. Using methane (fossil natural gas or bio-methane) the SMR-process for hydrogen production in general includes the following steps (Pham Minh, o.a., 2018)

- Pretreatment including removal of sulfur-containing compounds.
- Steam generation from demineralized water. Heat for steam production can come from combustion of methane or waste combustible gases from downstream H<sub>2</sub> separation. There is also the possibility to integrate various internal and external heat-flows for steam generation.
- Steam reforming process where methane is reacted with water (in the form of steam) to produce a syngas mixture, predominantly containing CO and H<sub>2</sub>. CO<sub>2</sub> and solid carbon are also formed in the process to some extent depending on process parameters. A heterogenous catalyst is needed for this highly endothermal process to take place. The reaction is favored by high temperature (typically 500–900°C) and a steam-to-carbon ration of 2.5-3, due to high methane conversion and repression of cake-forming, respectively.
- Water-gas-shift (WGS) reaction where the syngas is cooled to between 300–500°C and fed to the WGS reactor where CO and water is converted to CO<sub>2</sub> and H<sub>2</sub>. The WGS reaction is exothermic and residual heat from this step can usually be recovered for upstream steam generation, at least in large-scale facilities.
- H<sub>2</sub> separation where CO<sub>2</sub> is separated from the H<sub>2</sub> stream using PSA or equivalent technology.

For a state-of-the-art large scale SMR plant for  $H_2$  production (50,000 Nm<sup>3</sup>/h) from fossil natural gas (Linde, n.d.) a fuel consumption of around 740 GJ/h to produce around 50 kNm<sup>3</sup>/h is generally considered good. This represents a specific consumption of 14.88 MJ/Nm<sup>3</sup> H<sub>2</sub> and a hydrogen production efficiency of 72.7% (on a LHV basis). If intra-plant transfer of residual steam is included in the process the overall final efficiency can reach 86.2%. Other manufacturers have similar plants with a specific energy consumption for hydrogen production of 12.3 to 13.2 MJ/Nm<sup>3</sup> H<sub>2</sub> (Air Liquide, 2021b).

To convert methane and oxidants to syngas a reforming catalyst is mandatory. These are usually nickel-based catalysts with good cost/performance-ratio compared to nobel-metal based catalysts (Baysal, Gunay, & Yildirim, 2017). Alumina is often used as support material in industrial applications with a minimum lifetime of five years in continuous operation (Liu, Song, & Subramani, 2010). Several companies supply catalyst material for the SMR-process including Johnson Matthey, BASF, Haldor Topsoe, Thermo Fisher GMBH, and Süd-Chemie (Ferreira-Aparicio & Benito, 2005). There are several large industrial-scale plants to produce hydrogen from fossil methane operated by e.g., Linde, Haldor Topsoe, Howe-Baker, Foster Wheeler, Sanyo Electric, Osaka Gas Co, Air Liquide, Thyssenkrupp, and others (Linde, n.d.; Air Liquide, 2021b; Liu, Song, & Subramani, 2010; Ferreira-Aparicio & Benito, 2005). Linde has constructed over 200 individual plants with 1000 to 100,000 Nm<sup>3</sup>/h capacities [R4] and Air Liquide Engineering & Construction provides solutions in the 10,000–200,000 Nm<sup>3</sup>/h scale (Air Liquide, 2021b).

In principle most of the steps, system setup and features are consistent whether fossil natural gas or bio-methane is the feedstock for the SMR-process. One important difference, however, is the difference in scale as SMR-units with renewable feedstock currently are several orders of magnitude smaller. Capacity for these types of units is typically in the range of 100–1000 Nm<sup>3</sup>/h (IEA, 2012; Metacon, 2021; Preem, 2019). A second difference between small scale units with renewable feedstock and large-scale facilities with fossil ditto is the prerequisites for integration of the SMRprocess at the site of raw-material production (in the form of bio-methane in the renewable case). The possibilities for heat-integration at a biogas-facility is relatively smaller compared to what is possible at a petrochemical refinery (Pham Minh et al., 2018). Even so, possibilities for heat-integration exist and can be used to leverage the overall system efficiency of renewable and small-scale SMR.

## 4.2 STORAGE AND DISTRIBUTION OF HYDROGEN

Storage of hydrogen is complicated by the low density of the gas (0.083 kg/m<sup>3</sup> at 1 bar and 20 °C), making storage challenging in economic terms but also in other aspects, such as energy efficiency due to energy consuming conversion measures to deal with the low density. The same applies to the distribution of hydrogen which is still expensive. In this section a review of alternatives for hydrogen storage and distribution will be presented, with focus on the solutions most relevant for this project. Other solutions covered here – including liquefaction or conversion to ammonia or LOHCs – are more relevant for longer transport distances.

#### 4.2.1 Storage

The low density of hydrogen means that for storage to be done at any significant scale without taking up too much space, the density must either be increased, or storage must take place where space is not an issue. The former can be achieved in various ways, including through compression, liquefaction or conversion to other denser substances (e.g., ammonia, methane and ethanol) while the latter can be achieved by utilising underground storage facilities where a more moderate compression might suffice. In this section, an overview of existing state-of-the art alternatives are briefly presented, including compressed and liquid hydrogen, ammonia, liquid organic hydrogen carriers and solid-state storage methods. However, concerning distribution to and storage at hydrogen filling station, this is currently almost exclusively done using compressed hydrogen.

At some hydrogen production plants, there may be a low-pressure, intermediate, storage for the hydrogen gas. The main purpose of the intermediate storage is to keep a constant pressure and even out the flow of gas. As the volume of the low-pressure storage normally only corresponds to a few hours of gas production, it has a limited storage function.

#### Compressed hydrogen

As of today, the most common form of hydrogen storage is a compressed gas, with working pressures normally ranging from 200 to 350 bar for stationary storage (e.g., storage for distribution trucks or at a filling station), while it is often as high as 700 bar in mobile application (vehicle storage) (Damman, Sandberg, Rosenberg, Pisciella, & Johansen, 2020) In this way the density of hydrogen can be increased from 0.083 kg/m<sup>3</sup> (1 bar) to 15-40 kg/m<sup>3</sup> (for 200-700 bar). For intermediate storage – such as between the main storage and the dispenser at a filling station – pressures of up to 1000 bar are also possible, enabling quick and steady filling of 700 bar vehicles. For stationary storage either steel tanks or composite pressure vessels can be used, but for mobile applica-

tions, where the system weight is of more importance, composite tanks are often the preferred technology (Aarnes, Haugom, & Norheim, 2019).

While the compression increases storage density it also requires energy, which could correspond to as much as 8% of the energy content of the gas (Damman et al., 2020). Considering that the energy requirements increase with compression level, this gives a trade-off situation where more compact storage comes at the expense of energy losses.

A compressor station is located in the vicinity of the production site for the hydrogen gas and is used when the hydrogen gas is transported to another place from the production site in gaseous form. The compressor station is used to increase the pressure of the hydrogen gas to selected working pressure. The working pressure varies depending on whether the transport takes place in a gas pipeline or via truck transport with a container.

#### Liquid hydrogen

Another way of increasing the storage density of hydrogen is by storing it as liquid hydrogen. To liquify the gas it must be cooled to -253 °C and this temperature must then be maintained throughout the storage time. This means that an energy density of almost three times as much as for 350 bar compressed storage can be achieved (Berstad, Stang, & Nekså, 2009), but at the expense of high energy requirements, corresponding to 25-35% of the hydrogen energy content (Stolzenburg et al., 2013). Also, the boil-off of liquid hydrogen that takes place due its low boiling point means that if it stored for longer periods, losses might be large (Aarnes, Haugom, & Norheim, 2019). While hydrogen liquefaction is already a mature technique (Rivard, Trudeau, & Zaghib, 2019) it is yet to be applied in large scale and technology improvement and scale-up is expected to come with significant improvements with respect to both costs and energy efficiency (Cardella, Decker, & Klein, 2017).

A liquefaction plant is located in the vicinity of the production site for the hydrogen gas and is used when the hydrogen is transported to another place from the production site in liquid form.

#### <u>Ammonia</u>

Apart from changing the physical state of hydrogen, increased storage density can also be achieved through the conversion of hydrogen into other molecules. Ammonia is one such molecule which is formed through a catalytic reaction between hydrogen and nitrogen gas at elevated pressures (Sadler & Solgaard Anderson, 2018). Using only moderate cooling (to -33 °C) ammonia could be liquified and can then store hydrogen at a density of more than five times that of compressed hydrogen at 350 bar (Aarnes, Haugom, & Norheim, 2019). For this storage, insulated steel tanks can be used that are either single or double walled. Again, there is the issue of energy where the conversion of hydrogen to ammonia has an energy efficiency of 88% (HHV) (Smith, Hill & Torrente, 2019) and the reconversion can take place at 86 % (HHV) (Sadler & Solgaard Anderson, 2018) efficiency, giving a roundtrip efficiency of 76 % (Sadler & Solgaard Anderson, 2018). However, in applications where ammonia can be used directly some energy can be saved by omitting the reconversion step.

#### Liquid organic hydrogen carriers (LOHCs)

Another way of facilitating compact storage of hydrogen through conversion is by making use of liquid organic hydrogen carriers (LOHCs). These are chemical compounds with high hydrogen adsorption capacities (Rivard, Trudeau, & Zaghib, 2019). That can also be reversibly dehydrogenated and which – thanks to physical similarities to crude oil – benefit from the possibility to use existing infrastructure and distribution solutions (Damman, et al., 2020; von Wild et al., 2010). As one example of an LOHC, dibenzyltoluene can have a hydrogen storage density of 64 kg H<sub>2</sub>/m<sup>3</sup> (Niermann, Drünert, Kaltschmitt, & Bonhoff, 2019) giving an energy density almost three times that of compressed hydrogen at 350 bar . Although LOHCs are not today deployed as a common hydrogen storage method, several projects have been implemented during the last years (HySTOC, n.d.; Hydrogenious LOHC, 2021; FuelCellWorks, 2021; Collins, 2020; Demirocak, 2017), and it can offer a promising option for future storage and distribution, not least for long distance transport (Niermann, et al., 2021).

#### Solid state storage

Solid state hydrogen storage technologies include reversible hydrides (including metal hydrides and complex hydrides) and porous materials (e.g., metal-organic frameworks and carbon nanostructures) (Rivard, Trudeau, & Zaghib, 2019) Many reversible hydrides benefit from relatively high hydrogen storage capacity, while suffering from high operating temperature, slow kinetics and low reversibility (Demirocak, 2017). Conversely, porous materials tend to have fast kinetics and higher reversibility but generally lower hydrogen storage capacities (Demirocak, 2017).

In general, it can be said that, since several of the storage methods require significant amounts of energy for the conversion or physical alteration (compression/liquefaction) of hydrogen, for small-scale applications, hydrogen should preferably be stored in the form it will later be used, in order to avoid conversions as far as possible.

#### 4.2.2 Methods for distribution

Hydrogen distribution can be done in many ways, including using truck, train or ship transport, but also through pipeline transport. These have different attributes, making them suited for different forms of hydrogen and for different scales and distances. In this section, state-of-the art distribution methods will be described for the methods currently used for distribution of compressed hydrogen for use in road transport.

#### Truck transport

Due to the decentralised nature of refuelling for road transport, distribution with trucks is a common way of distributing hydrogen for this application. Hydrogen is then stored in cylindrical steel or low-weight composite vessels, which are bundled in containers that function as mobile gas storages (Umoe Advanced Composites, 2018; Processkontroll GT, 2021). Containers can either be *swap bodies* (also known as *hook containers*) (Figure 5) or *ISO containers* (Figure 6). At the filling station hook containers can be offloaded from the truck using the built-in hook lift, while ISO containers are either left on the trailer on which they arrived or must be offloaded using a lifting device. The hydrogen storage capacity of containers depends on the working pressure of the vessels used but also on the size of the container (and number of pressure vessels they can fit). ISO containers can be found in lengths of 20 ft, 40 ft or 45 ft and heights of 2.6 m (standard, std) or 2.9 m (high cube, HC), while hook containers are normally 20 ft and standard height. For 20 ft standard height containers, around 350 kg H<sub>2</sub> can be stored at a working pressure of 350 bar, while a 40 ft high cube container can store around 900 kg H<sub>2</sub> at the same working pressure (Umoe Advanced Composites, 2021). The full storage capacity of one truck in turn depends both on which pressure vessels that are used and which/how many containers are loaded onto the truck, limited by the total train length and weight according to rules from the Swedish Transport Agency (Transportstyrelsen, 2021a; Transportstyrelsen, 2021b).



Figure 5. 20 ft swap body or hook container, offloaded with built-in hook lift (Hjort & Tamm, 2012)



Figure 6. 40 ft ISO container, requiring separate lifting device for offloading (Umoe Advanced Composites, 2018).

#### Pipeline transport

Another way to transport gaseous hydrogen to a refueling station is by using pipelines. Such a solution has been used to supply a hydrogen refuelling station in Sandviken since 2016 (Dagens Industri, 2016). The technology for hydrogen pipelines is similar to that of methane pipelines, but with some differences related to the chemical properties of the two gases. The first is related to the pipe integrity, where the small molecule size of hydrogen gas makes it absorb to the steel walls of the pipelines (Entsog, GIE & Hydrogen Europe, 2021). This is called *hydrogen embrittlement* and can lead to a reduction of ductility and load bearing capability of the pipeline (Entsog, GIE & Hydrogen Europe, 2021). The second is related to that hydrogen has a lower energy density than methane, meaning that larger pipe capacities are needed to supply the same amount of energy (Aarnes, Haugom, & Norheim, 2019).

### 4.3 HYDROGEN REFUELLING STATIONS

Despite the number of operational hydrogen refuelling stations has increased in recent years only 540 station were operational at the end of 2020 (IEA, 2021a) and the majority of these are located in three countries Japan (140), Germany (90) and China (85). Lack of economies of scale, low individual station capacities, low utilisation rates and relatively high cost of hydrogen refuelling equipment means that the refuelling stations currently typically account for a significant share of the cost of hydrogen at the dispenser (Reddi, Elgowainy, Rustagi, & Gupta, 2017). The design and configuration of the hydrogen refuelling station is primarily defined by the state of hydrogen supplied to the station (gaseous or liquid) and the daily refuelling profiles (Reddi et al., 2017; Samuelsen, Shaffer, Grigg, Lane, & Reed, 2020). Key components typically include compressor(s) (medium or high pressure depending on the configuration of the station), pressurised storage, pre-cooling equipment, dispenser(s) and control and safety equipment. All of these components are commercially available and there are several actors globally that can offer specialised or turnkey solutions for hydrogen refuelling stations. However, hydrogen refuelling station are still in the early phases of commercialization and further technology development and cost reductions can be expected with higher market penetration. Reddi et al. (2017) show how different market parameters and improvements and cost reduction of refuelling station components affect the total refuelling costs and finds that higher utilisation rates and equipment cost reduction via learning and economies of scale could reduce costs significantly (from \$6-\$8/kg H2 to \$2/kg H2). Based on estimates of technological maturity and cost reduction potential the authors differentiate between three categories of refuelling equipment; Group 1, includes low-pressure storage and cryogenic storage which are assumed to be mature and have a low cost reduction potential, Group 2 includes highpressure storage, precooling equipment, cryogenic pump, which have been proven viable and are expected to have a moderate potential for cost reduction, and, Group 3, including dispensers, compressors, controls and safety equipment, which have significant potential for technical development and cost reductions through learning and economies of scale Kurtz et al. (2019) and Samuelsen et al. (2020) point to the importance of reliability for hydrogen refuelling systems and components both to limit maintenance costs (which can be significant) and to live up to the expectations from customers. Previous experiences with operation of hydrogen refuelling stations have shown that compressors, dispensers, chillers, and the overall refuelling system, tend to be more prone to malfunction whereas equipment such as hydrogen storage, electrical, and safety systems are generally more robust.

#### 4.4 SUMMARY

Alkaline Water Electrolysers AEL and steam methane reformers are the chosen production technologies as they have a high TRL level, there are several existing suppliers on a suitable scale and the technology fits the function of the system solutions. Suitable distribution alternatives with a high TRL level and existing suppliers are considered to be gas pipes or hydrogen containers. Hydrogen containers distributed on the road to the hydrogen filling station are chosen for long distance transports from centralised production plants while gas pipelines are suitable for short distances in the decentralised case. There are several suppliers of hydrogen filling stations that can refuel vehicles with 350 and/or 700 bar pressure that are considered to have a high TRL level.

System solution	Production		Distribution		Filling station	
	TRL Level (1-9)	Available suppliers	TRL Level (1-9)	Available suppliers	TRL Level (1-9)	Available suppliers
1a&b. Central electrolysis	9	Yes, Several	9	Yes, Several	8-9	Yes <sup>2</sup>
2a&b. Central reformation	8-9 <sup>1</sup>	Yes, Several <sup>1</sup>				
<b>3a&amp;b</b> . Decentralised electrolysis	9	Yes	9	Yes, Several		
4a&b. Decentralised reformation	8-9 <sup>1</sup>	Yes, a few <sup>1</sup>				

Table 3. The	TRL and	available	suppliers	for	the	different	cases
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(1) There are suppliers who supply small scale SMR technologies, but they lack reference cases and in order to increase the production capacity in the centralised and the decentralised cases several of those plants must run together simultaneously. There exists however several SMR suppliers that deliver large scale plants that have several reference cases.

(2) There are suppliers of filling stations but there are not so many suppliers who have reference cases for the capacity range in this study.

# **5 REVIEW OF COSTS**

The present chapter gives an overview of the different technology options and costs for defined pathways.

## 5.1 HYDROGEN PRODUCTION

This section describes the cost of hydrogen production as well as low pressure storage and the subsequent cost of increasing the pressure. The costs for electricity and biogas are shown in Table 20 in appendix A.

#### 5.1.1 Water electrolysis

The available literature presents a wide range of estimates for electrolyser investment costs, typically between 400-2000 EUR/kWel for alkaline and 750-3000 EUR/kWel for PEM (e.g., (IEA, The Future of Hydrogen, 2019; Fuel Cells and Hydrogen Joint Undertaking, n.d.; Christensen, 2020). The estimates are most often based on expert assessments or similar, and only rarely based on actual cost data from manufacturers. The wide range of cost estimates can be explained by rapid technology development, varying system sizes and some uncertainty regarding the economy of scale effects for larger units (many currently developing projects are significantly larger than existing, operational systems). Review reports and articles offer a way to get an overview of the varying cost estimates but suffer from the general drawback of relying on data that can be up to several years old, and at risk of being outdated already at publication due to rapidly decreasing cost estimates. On the other hand, reliable and transparent cost data from manufacturers is very scarce. However, a review article published within the framework of the Hydrogen Implementing Agreement of the IEA contains actual cost data from electrolyser manufacturers NEL Hydrogen (alkaline electrolysers) and ITM Power (PEM electrolysers) (Proost, 2019). The covered input power range (system power) is 0.4-90 MW for alkaline and 0.4-4 MW for PEM. The cost data and power rating include the electrolyser stack and peripheral equipment such as: transformer(s), control system, water demineraliser, gas analysers and separators, gas scrubbing and purification systems, recirculating pump(s), and compressor(s) for compression to 15 bar(g). Equipment and direct installation costs are included, while indirect costs such as site preparation, engineering etc. are not included but applied to the entire investment for each system solution as described in section 2.4.

In the present work, alkaline electrolyser cost functions were derived based on data from NEL Hydrogen described above. The resulting cost function given in Table 4 and plotted in Figure 7 together with the investment cost data points. Electrolyser costs for hydrogen plants with production capacities at 5, 10, 25 and 50 GWh/year (assuming an electrolyser system efficiency of 62 %, including peripheral equipment as described above but excluding the cooling system) have been calculated using the developed cost function and included in the figure. The specific cost curve has a knee at around 2 MW<sub>el</sub> (about 40 kg H2/hr), corresponding to the point where the electrolyser unit goes from single stack to multi stack – i.e., above this point the technology is modular and plants consist of several stacks.

In the present work, all electrolysers were dimensioned to match the total system production rate – i.e., to have annual production rates according to Table 27 assuming 100 % capacity utilisation.

Table 4. Investment cost functions for economic evaluation of electrolysers. Purchased and direct in-
stallation costs are included. Indirect costs such as site preparation, engineering etc. are not included
but applied to the entire investment for each system solution as described in section 2.4.

	Value	Unit	Reference	Comment
Single stack (i.e., system size <2.1 MW <sub>el</sub> )	1116*P <sup>-0.63</sup>	EUR/kW <sub>el</sub>	[11]	P refers to the system power rating in MW <sub>el.</sub> Valid range: 0.4-2.1 MW <sub>el</sub>
Multi stack (i.e., system size >2.1 MW <sub>el</sub> )	742*P <sup>-0.10</sup>	EUR/kW <sub>el</sub>	[11]	P refers to the system power rating in MW <sub>el.</sub> Valid range: 2.1-90 MW <sub>el</sub>



Figure 7. Alkaline electrolyser cost function based on data from NEL Hydrogen available in (Proost, 2019). Here, CAPEX data includes equipment and direct installation costs. Cost for electrolysers with capacities 5, 10, 25 and 50 GWh/year have been calculated assuming a system efficiency at 62 % on LHV. Specific costs are 63 180, 40 830, 34 480 and 32 270 EUR/kgH<sub>2</sub>/h for annual hydrogen production levels of 5, 10, 25 and 50 GWh/year, respectively.

#### 5.1.2 Methane reforming

Small scale SMR for renewable hydrogen production from biogenic feedstocks is not yet a fully developed and established market worldwide, and the plants being commissioned are not optimized according to economy of scale. Instead, other more modular, and adaptable solutions are generally preferred, drawing from benefits such as dispatchability and low maintenance. Several suppliers for modular solutions exist however, ranging from subdivisions of large multinational companies to smaller more entrepreneurially oriented firms. Examples include Haldor Topsoe, Air Products, HyGear, Linde, Mahler, Metacon, etc (IEA, 2012). In the Swedish context, installations of small-scale SMR-facilities are planned, for example in the Gothenburg area.

The specific investments cost for SMR facilities vary in literature but follow a clear trend according to economy of scale for large scale facilities (Jakobsen & Åtland, 2016). For smaller scale, there is a sharper decline in the specific cost for hydrogen production (in EUR per kg  $H_2/h$ ) the smaller the unit is, and this is true for both modular and non-modular (place-built units). Above a certain size however, the decrease in specific cost levels out to become completely independent of further capacity increase for the modular case (due to the concept of modularity), and to have only a minor dependence for the non-modular facilities. In Figure 8, the relation between production capacity and specific hydrogen production cost is depicted, both for the modular and the non-modular designs.



Figure 8. SMR cost functions for modular and non-modular units. Based on data from (Metacon, 2021; Preem, 2019; IEA, 2012). For modular units the specific costs are around: 75 000, 75 000, 68 000, and 68 000 EUR/kgH2/h; for non-modular units around: 110 000, 75 000, 42 000, and 40 000 EUR/kgH2/h, for annual hydrogen production levels of 5, 10, 25 and 50 GWh/year, respectively.

There are recently launched modular, and container based self-contained SMR processes available. The capacity of these types of units are from 10 to 250 Nm<sup>3</sup>/h H<sub>2</sub> (or 0.9 to 20.8 kg/h). The Swedish company Metacon, for example, produces such systems for the commercial market. Their units deliver hydrogen at over 99.999 % purity (when using bio-methane) at either 15 bars for the 250 Nm<sup>3</sup>/h system or 7 bars for the other, both at ambient temperature. The operating range is between 50 and 100% and the unit has a specific consumption of around 0.4 Nm<sup>3</sup> methane per Nm<sup>3</sup> hydrogen produced. Table 5 specifies parameters for such units.

System Capacity <sup>1</sup>	200 NCMH	250 NCMH	
Reformer Plant			
Rated Hydrogen production	[Nm³/h]	200	250
Operating range	[%]	50–100	50-100
Hydrogen delivery pressure	[bar <sub>g</sub> ]	7	15
Delivered hydrogen content	[% vol]	≥99.999 %	≥99.999 %
Delivered stream gas temperature	[°C]	Amb. Temp.	Amb. Temp.
Plant media specification			
Natural gas	[Nm³/h] (IEA, 2021b)	80 ± 10 %	100 ± 10 %
Specific consumption	[Nm <sup>3</sup> NG/Nm <sup>3</sup> H2]	0.40 ± 10 %	0.40 ± 10 %
electrical power consumption	[kW]	<25	<35
De-ionized water	[l/h]	200	250
Nitrogen (for plant START/STOP only)	[Nm <sup>3</sup> /purging]	8	10

Table 5. Parameters for modular SMR-units supplied by Metacon (2021).

 For comparison between system capacity of modular SMR-units in this table and filling station capacities: 5 GWh/y equals 190.5 Nm<sup>3</sup>/h.

#### 5.1.3 Low-pressure storage at production site

Low-pressure storage and associated low-pressure compression capacity to handle demand variations were assumed at centralised as well as decentralised production sites. At the centralised production site, there is also a terminal with dedicated compressors for filling the tube trailers. The above system components are described in this section, for centralised and decentralised production, respectively.

#### Centralised production

For centralised production, dimensioning and costing of the low-pressure storage was based on data derived from HDSAM (Hydrogen Delivery Scenario Analysis Model) developed by the Argonne National Laboratory (Hydrogen Delivery Scenario Analysis Model, n.d.). HDSAM is an Excelbased model used to determine system costs of various hydrogen delivery scenarios. In the present work, the HDSAM module for analysing tube-trailer delivery to fuelling stations from a centralised production plant was used. A total system capacity equal to 4120 kg/day (50 GWh/year) with 5 or 10 stations (i.e., representing the cases analysed in this report) was modelled using HDSAM and resulting equipment specifications and costs for the truck-loading terminal (adjacent to the production site) were used without modification other than an updated storage cost (see below) and currency adjustment.

HDSAM includes a small 85/170 bar (min/max) storage system at the truck-loading terminal to handle short term supply/demand variations. The useable storage capacity is 25 % of the daily pro-
duction capacity. Given the specified max-min pressures, the useable storage capacity is about 50 % of the total storage capacity – i.e., the total storage capacity is about 50 % of the total daily production capacity at the site. The specific cost was assumed to be constant at 9600 SEK/kg total storage capacity (including equipment and direct installation costs). This is a slight decrease compared to cost data from HDSAM, motivated by lower costs identified in cost specifications by equipment suppliers.

The low-pressure storage is filled by dedicated storage compressors. Dimensioning, costing and annual power consumption was based on HDSAM output, as summarised in Table 6.

Table 6. Parameters for the distribution terminal for centralised production. Specific values calculated for 4120 kg/day (50 GWh/year). Costs are given excluding indirect cost factors for site preparation, contingency etc (see section Fel! Hittar inte referenskälla.).

Design and operating parameters		
Storage compressors, total capacity	[kg/hr]	178
Truck loading compressors, total capacity	[kg/hr]	600
Compression energy demand (storage+loading)	[kWh <sub>el</sub> /kg]	1.33
Low-pressure storage capacity	[kg]	2120
Low-pressure storage, min/max pressure	[bar (a)]	85/170
Economic parameters		
Compressors (storage+loading)	[SEK/kg]	3.11
Low pressure storage	[SEK/kg]	1.40
Other terminal equipment (incl. electrical, control and safety)	[SEK/kg]	0.90

#### Decentralised production

For decentralised production, the storage was dimensioned based on the cascade compressor load profiles obtained from the HDRSAM model developed by the Argonne National Laboratory (n.d.). See section 5.3 for a description of the model and relevant input/output used in the present work.

In the decentralised production case, a low-pressure storage is required to balance the varying demand of the cascade compressor (see also section 5.3) and the constant production rate of the hydrogen production unit (electrolyser or reformer). In the present work, the operating profile (kg  $H_2/hr$ ) of the cascade compressor was obtained from the output of the HDRSAM-model which was used to dimension the refuelling station (see also section 5.3). The obtained operating profile was combined with the assumed continuous production profile of the hydrogen production unit to calculate the required (useable) storage capacity. The min/max pressure of the storage system was assumed to be 50/250 bar and the specific investment cost was assumed to be the same as in the centralised case (9600 SEK/kg, equipment and direct installation costs). The storage system was assumed to be filled continuously and a low-pressure compressor was dimensioned to match the hourly production rate of the hydrogen production unit. The compressor capacity (kW<sub>el</sub>), equipment cost, and annual power demand (kWh) were calculated using equations derived from the HDRSAM model. The compressor engine was dimensioned according to

$$P_{el}[kW] = \frac{S}{\eta_{engine}} \frac{QZTR}{M_{H2}\eta_{comp}} \frac{N\gamma}{\gamma - 1} \left( \left(\frac{P_{out}}{P_{in}}\right)^{\frac{\gamma - 1}{N\gamma}} - 1 \right)$$

Where  $P_{el}$  is the electricity required for the compressor engine,  $\eta_{engine}$  and  $\eta_{comp}$  are engine (92 %) and compressor (75 %) efficiencies, S is the engine over-size factor (1.1), Q is the mass flow rate (kg/s), Z is the compressibility factor, T is the inlet temperature (311 K),  $M_{H2}$  is the molar mass of hydrogen (g/mol), N is the number of compressor stages (calculated assuming a pressure ratio of 2.1 per stage),  $P_{out}/P_{in}$  is the pressure ratio (250/15, where 15 bar (a) is the hydrogen production pressure),  $\gamma$  is the specific heat ratio (1.4) and R is the universal gas constant (in J/mol,K).

The equipment cost (including direct installation costs) was calculated based on the engine size according to

Equipment cost [SEK 2019] = 598 000 × 
$$(P_{el}[kW])^{0.6}$$

The average power demand, Pel,average, during operation was estimated according to

$$P_{el,average}[kW] = \frac{S}{\eta_{engine}} \frac{QZTR}{M_{H2}\eta_{comp}} \frac{N\gamma}{\gamma - 1} \left( \left( \frac{\ln\left(P_{out,max}/P_{out,min}\right)}{P_{in}} \right)^{\frac{\gamma - 1}{N\gamma}} - 1 \right)$$

Where ln is the natural logarithm and  $P_{out, max/min}$  are the max/min pressures of the low-pressure storage.

A summary of cost and operating parameters for the low-pressure storage and the associated compressors is given in Table 7. Other refuelling station equipment is discussed in 5.3. Table 7. Parameters for the low-pressure storage system for decentralised production cases. Specific values calculated for 150 tonnes/year (5 GWh/year) and 300 tonnes/year (10 GWh/year), with investment costs annualised according to section 2.4. Costs are given excluding indirect cost factors for site preparation, contingency etc (see section 2.4.

Design and operating parameters	5 GWh	10 GWh	
Storage compressors, total capacity	[kg/hr]	17	34
Compression energy demand (storage)	[kWh <sub>el</sub> /kg]	1.2	1.2
Low-pressure storage capacity	[kg]	93	155
Low-pressure storage, min/max pressure	[bar (a)]	50/250	50/250
Economic parameters			
Compressors (storage)	[SEK/kg]	1.93	1.42
Low pressure storage	[SEK/kg]	0.81	0.67

# 5.2 DISTRIBUTION

The cost of hydrogen distribution using road transport for the centralised scenarios was calculated for a distance of 0 to 150 km and for different trailer combinations. The trailer combinations are limited in total weight (64 tonnes) and length of freight train (24 m) according to rules from the Swedish Transport Agency (2021b). Within these limits, there is a large number of possible combinations of different lengths (20 or 40 feet), heights (standard or high cube) and working pressures (250 or 350 bar) available from technology suppliers. Table 8 illustrates a selection of the possible combinations (including the most cost-efficient ones), for which the specific transport cost has been calculated. Assumptions on costs that have been included in the distribution cost can be found in Appendix in Table 22.

Table 8. Possible combinations of container sizes (height and length) and maximum allowable weights. All containers have hydrogen storage at 350 bar if not stated otherwise. Based on data from (Umoe Advanced Composites, 2021) and (Processkontroll GT, 2021).

Container combination	Total hydrogen capacity [kg]
3x20 ft (feet) ISO std (standard)	1068
3x20 ft ISO std (250 bar)	1050
1x20 ft ISO std, 2x20 ft ISO HC (high cube)	1226
1x40 ft ISO std, 1x20 ft ISO std	1090
1x40 ft ISO HC, 1x20 ft ISO std	1239
1x40 ft ISO std, 1x20ft ISO HC	1169

The calculations for the 5 and 10 GWh scenarios are displayed in Figure 9, indicating a large span of costs for the included container combinations. Comparing the results for the two scenarios, the specific distribution costs (distribution cost per kg  $H_2$ ) are lower for the 10 GWh scenario. For this scenario the most cost-efficient distribution solution (2x20 ft ISO HC and 1x20 ft ISO std) gives a specific distribution cost of ~8.4 SEK/kg  $H_2$ , for 150 km distance, while the corresponding cost for the most cost-efficient solution (same combination) in the 5 GWh scenario is ~10.7 SEK/kg  $H_2$ . The cost difference can be explained by the increased (doubled) need for investments in gas storage containers in the 5 GWh scenario, as the number of hydrogen filling station is doubled, and each station is assumed to require as many containers as for the 10 GWh scenario (one for storage at station, one for replacing it). Since the hydrogen consumption is halved at each station, this means that the containers need only to be replaced half as often, but since this is done for twice the number of stations the number of transports is still assumed to be the same as for the 10 GWh scenario. The investment in container is thus assumed to be increased, while any savings in transport costs due to possible closer distance between this doubled number of stations is neglected.



Figure 9. Specific distribution costs for the container combinations in Table 8, calculated for the 5 GWh (turquoise) and 10 GWh (red) filling station scenarios. The results show the large span of costs for different container combinations but also that the most cost-efficient option (dotted line) for the two scenarios can offer distribution at a cost of ~10.7 SEK/kg H2 (5 GWh) and ~8.4 SEK/kg H2 (10 GWh) for a 150 km distance. Based on data from Umoe Advanced Composites (2021) and Process-kontroll GT (2021).

# 5.3 HYDROGEN REFUELLING STATION

Equipment dimensioning and costing for all refuelling stations was done using the MS Excel-based model HDRSAM (Heavy Duty Refuelling Station Analysis Model) developed by Argonne National Laboratory (n.d.). Given a specified utilisation profile (i.e., number of trucks refuelling per hour of the day and average truck fuel demand) the model dimensions fuelling station components looking to minimise the total cost per kg hydrogen dispensed (CAPEX+OPEX). The model only covers hydrogen stations (i.e., modelling CNG stations is not possible). The following station types can be modelled by HDRSAM:

- Fuelling pressure
  - 350 or 700 bar
- Hydrogen delivery mode
  - Tube-trailer or pipeline
- Dispensing option
  - Cascade dispensing
  - Booster compressor

For all station configurations analysed in the present work, the station cost was calculated using HDRSAM for a station type with 700 bar cascade-dispensing and tube-trailer delivery. This means that the tube-trailer case in HDRSAM was used for decentralised as well as centralised production, despite there being no tube-trailers in the centralised case. However, from the perspective of the HDRSAM model, the low-pressure storage used in the centralised case (see section 0) is equivalent to a tube-trailer albeit with different pressure levels. In the decentralised case, the tube-trailer min/max pressure in HDRSAM were set to match the low-pressure storage pressure (50/250 bar), while the actual distribution pressure (30/350 bar, see section 0) was used in the centralised case.

Dimensioning, investment costs and operating costs for the following equipment are included in the HDRSAM:

- Cascade storage at three pressure levels (max pressure 940 bar, min pressure 800/610/330 bar). Note that the storage pressure in cascade systems are higher than the maximum fuel-ling pressure (in this case, 700 bar).
- High pressure compressor(-s) for filling the cascade storage from the tube-trailer or low-pressure storage
- Refrigeration system
- Dispenser(-s)
- Electrical, control and safety

Two different station cases were considered and dimensioned assuming the utilisation profiles given in Figure 10. Note that the capacity of the smaller station is higher than 411 kg/day (the dimensioning volume for small stations in this work) due to the assumed fuelling volume of the trucks and the discrete number of trucks refuelling per day. However, this discrepancy has a negligible impact on the *specific* hydrogen production cost, which is the metric of comparison used in this work.



Figure 10. Assumed utilisation profile for the dimensioning of small (5 GWh/year) and large (10 GWh/year) stations. Only heavy-duty trucks were assumed to use the station and each truck filling was assumed to be 55 kg. Total daily volume: Small – 5 GWh (420 kg), Large – 10 GWh (825 kg).

A summary of the most important cost and operating data derived from HDRSAM is given in Table 9.

Table 9. Parameters from the HDRSAM model for small (5 GWh/year) and large (10 GWh/year) stations. Specific values calculated for 160 tonnes/year (5 GWh/year) and 300 tonnes/year (10 GWh/year), with investment costs annualised according to section 2.4. Costs are given excluding indirect cost factors for site preparation, contingency etc (see section 2.4). The costs for low-pressure storage and compression at the decentralised stations (see section 0) are not included in compres-sion and storage in this table. Note that the modelled annual capacity of the stations (in tonnes/year) differs slightly from the assumed station capacities (5 or 10 GWh). The discrepancy is due to the as-sumed fuelling volume of the trucks and the discrete number of trucks refuelling per day. However, this discrepancy has a negligible impact on the *specific* hydrogen production cost, which is the metric of comparison used in this work.

		Decentra	alised	Centralis	sed
Design and operating parameters		5 GWh	10 GWh	5 GWh	10 GWh
Number of dispensers	[-]	1			
Filling rate	[kg/min]	3.6			
Compressor capacity (total)	[kg/hr]	32.0	64.6	32.0	64.6
Compressor rated power (total)	[kW <sub>el</sub> ]	85	172	104	210
Compressor specific energy demand	[kWh <sub>el</sub> /kg]	1.50	1.50	1.45	1.45
Cascade storage capacity	[kg]	871 1005 871 1			1005
Cascade storage max pressure	[bar (a)]	940			
Refrigeration spec. energy demand	[kWh <sub>el</sub> /kg]	0.05			
Total spec. energy demand	[kWh <sub>el</sub> /kg]	1.55	1.55	1.50	1.50
Economic parameters					
Compressor cost	[SEK/kg]	5.16	5.53	5.82	6.23
Cascade storage cost	[SEK/kg]	10.57	6.50	10.57	6.50
Other equipment, incl. electrical, control and safety	[SEK/kg]	4.55	2.76	4.55	2.76
Sum	[SEK/kg]	20.28	14.79	20.94	15.49

# 6 SYNTHESIS OF COSTS

In this section the cost estimates are synthesised. First, the production costs, then distribution, and finally the filling station are summarised. The costs presented is the cost for compressed hydrogen at filling station to end customer and the vehicle capital cost including fuel efficiency are excluded.

The total hydrogen related costs including production, distribution and filling station are presented in Figure 11. A breakdown of costs of hydrogen production is shown in Figure 14 for distribution and Figure 15 for filling stations.

Overall, hydrogen produced based on electrolysis has the lowest total cost compared to production via steam methane reformer. Moreover, decentralised pathways (3-4) have lower costs compared to centralised pathways (1-2).



Figure 11. Costs per amount of hydrogen at filling station in SEK/kg H<sub>2</sub> for the eight calculated cases. Blue colour indicates the cost for production, orange colour indicates the cost for distribution of hydrogen and grey colour indicates the cost for the hydrogen filling station. 1a and 1b is Central Electrolyser and 2a and 2b is Central Steam Bio-Methane Reformer, both with a capacity of 150 tons H<sub>2</sub>/year & filling station respective 300 tons H<sub>2</sub>/year & filling station. 3a and 3b is Decentral Electrolyser and 4a and 4b Decentral Steam Bio-Methane Reformer, both with a capacity of 150 tons H<sub>2</sub>/year & filling station respective 300 tons H<sub>2</sub>/year & filling station.

There are cost advantages due to the scale of operation for production, distribution and the filing stations, for the centralised cases the effect of having hydrogen filling stations with larger capacities (10 GWh) only has a noticeable effect on the specific production cost for the filling station part. The reason for that is that the centralised pathways (1-2) have the same production capacity.

The cost advantages due to the scale of operation for the centralised pathways (1-2) has no noticeable effect because the costs also include the cost for a compressor station as well as the distribution costs. The compressor station is used to fill the mobile hydrogen gas storages that are used to transport hydrogen to the filling stations. Section 6.1 shows the cost distribution for production of hydrogen.

# 6.1 PRODUCTION

The total hydrogen related costs for production are presented in figure 12 below. A breakdown of costs of hydrogen production is shown in figure 13. The difference between the two figures is how the cost is presented. The costs have been allocated as the total costs for production, intermediate storage and compressor station for figure 12 and the cost for production, intermediate storage and compressor station have been breakdown into the costs for annuity, electricity, personnel, service and maintenance, biogas, nitrogen and water in figure 13.

Overall, hydrogen produced based on electrolysis have the lowest total production cost compared to steam methane reformer. The difference between central and decentralised production is the cost of the compressing station in centralised production. Decentralised production (5-10 GWh  $H_2$ ) has a higher cost without the cost for the compressor station compared to centralised pathways (50 GW  $H_2$ ).



Figure 12. Production costs in SEK/kg H<sub>2</sub>. The costs have been allocated as the total costs for production for electrolyser (light blue colour), and reformer (light green colour), intermediate storage (light yellow colour), and compressor station (blue colour).

The production cost for both central and decentralised production largely consists of the cost of electricity and biogas, respectively. See figure 13 below.



Figure 13. Breakdown of production costs in SEK/kg H2. An annuity is a series of payments made at equal intervals which in this case is the annual payment over 15 years for the investment.

#### 6.2 **DISTRIBUTION**

The cost of distribution hydrogen largely consists of the transport, i.e. the actual relocation of the hydrogen gas. The other major cost item consists of the costs for the mobile hydrogen storages that are shown as annuity. The third cost item is the cost of switching mobile gas storage. The costs are shown in figure 14 below.



Figure 14. Breakdown of distribution costs in SEK/kg H<sub>2</sub>. An annuity is a series of payments made at equal intervals which in this case is the annual payment over 15 years for the investment.

# 6.3 HYDROGEN REFUELLING STATION

The cost of a hydrogen station consists largely of the investment while the remaining cost items are smaller. Service and maintenance are also a major cost while the cost for electricity and personnel is smaller relative to the rest of the costs.



Figure 15. Breakdown of costs for hydrogen filling station in SEK/kg H<sub>2</sub>. An annuity is a series of payments made at equal intervals which in this case is the annual payment over 15 years for the investment.

# 6.4 SENSITIVITY ANALYSIS

As described in section 2.4.1, a systematic variation of costs has been carried out in order to determine the importance of different cost parameters as well as to understand how different development can affect the total price and competitiveness of the different solutions being studied and compared.

The total costs, in section 6.1 for production costs, in section 6.2 for distribution costs and for hydrogen refuelling station in 6.3, shows the cost picture for today's production with the costs estimated to be the most likely in respect to the knowledge gathered by the project team. The technologies studied are assessed as mature, but still, a development of technologies and processes will most likely make future cost reductions possible. On the other hand, important are also the cost for electricity which is influenced not only by production costs but also by supply and demand and other market conditions.

Below, in this chapter, there is a description of the different sensitivity analysis performed as well as the result shown in graphs. The sensitivity analysis is presented in graphs where one parameter is varied, and the results is shown as a variation in total hydrogen costs.

To make the results from the assessment easier to read and assess, a yellow mark in each graph shown in Figure 16 to Figure 24 indicates the cost level span for the base cases.

#### 6.4.1 Investment costs

The investments costs for important parts of the parameters needed for hydrogen production, handling, transportation, storage as well as the dispensers will most likely develop over time. As there can be a general cost development for all types of investments (Figure 16) as well as for specific parts, both kinds of analyses have been performed. For specific parameters selected it has been the electrolyser costs (Figure 17) and reformer costs (Figure 18) that has been varied.

In the general variation cost case, it is the following parameters that has been varied in relation to investment costs: *electrolysers, reformers, biogas compression step, compressor station, filling station, low pressure storage including compressor, hydrogen pressure reduction.* The investment cost parameters varied in the general case has been varied all with the same percentage in Figure 16.

The general variation of investments costs gives an almost equal cost reduction between the different system solutions (see Figure 16). Isolating investment cost for the electrolyser gives the natural result that only systems solutions with electrolyser hydrogen production will vary (see Figure 17). Similar results for reforms being the parameter being varied can be seen in Figure 18.



Figure 16. Sensitivity analysis - Investment cost of components variation. Results in SEK/kg for the eight calculated cases.



Figure 17. Sensitivity analysis - Investment cost of electrolyser variation. Results in SEK/kg for the eight calculated cases. Note that systems using reformers for hydrogen production from biogas will not be affected by variation in electrolyser cost as no electrolysers being used in these systems.



Figure 18. Sensitivity analysis - Investment cost of reformer variation. Results in SEK/kg for the eight calculated cases. Note that systems using electrolysers for hydrogen production will not be affected by variation in reformer cost as no reformers being used in these systems.

#### 6.4.2 Intermediate goods

The most important intermediate goods used in the hydrogen production under study are electricity and biogas. The dependence on biogas price is only valid for the reformer production (case 2a, 2b, 4a and 4b). Electricity is used in all production but to a much larger extent consumed in electrolysers (case 1a, 1b, 3a and 3b).

Variation of costs for electricity can be seen in Figure 19 and variation of costs for biogas in Figure 20.

The price of electricity for the consumer mainly consists of:

- The electricity trading cost for the electricity consumed.
- The electricity network cost for transmission of electricity to the user.
- Taxes and fees: energy tax, VAT and fees to authorities.

The basic cost for the calculations has been a total cost for electricity of 1 SEK/kWh including network costs, taxes, and fees.

Access to electricity at a significantly lower level than the base cases used within this study could potentially lower the total costs for hydrogen at fuel station significantly. The results from the sensitivity analysis shows clearly that access to electricity and or biogas to a significantly lower cost level will have the effect that the total price per produced hydrogen also will decrease significantly. Large electricity consumers already today are able to purchase electricity at levels around 75 % of the base price used in this study.

It is the price of electricity that affects the total production price of hydrogen the most and especially for the system solutions using electrolysers (see Figure 19). Also, system solutions using reformers consumes electricity, but at a much lower level per produced amount of hydrogen why the hydrogen production price being less affected by a change in the price of electricity. Also, the price for biogas will affect the production cost of hydrogen for the production based on reformers (see Figure 20).



Figure 19. Sensitivity analysis - Price of electricity. Results in SEK/kg for the eight calculated cases. Note that systems using reformers for production of biogas will be affected by electricity price variation to a much less degree than the systems using electrolysers for hydrogen production.



Figure 20. Sensitivity analysis - Biogas price variation. Results in SEK/kg for the eight calculated cases. Note that the systems using electrolysers for hydrogen production will not be affected if only the cost for biogas being varied as no biogas is consumed in these systems.

#### 6.4.3 Variation of utilisation rate

The base cases for calculations in this study assumes that the production and the utilisation of the system is at 100 %. That is probably far from reality today and will of course not be the case in the future for all stations at all time. To show how the utility will affect cost levels two different kind of utilisation cases has been analysed. We have chosen to vary the production between 40 % up to 120 % of the base case. In some cases, it might not be possible produce more hydrogen than the 100 % of the base case without additional investments, but that will depend on the actual design of the system under study.

The first case is where the utilisation rate of both centralised and decentralised production as well as the utility of the filling station is being varied which is shown in Figure 21.

The second case is where the utilisation of the production at centralised production remains unchanged but the decentralised production as well as utilisation at the filling stations are being varied. This can also be seen as the case if the price for purchased hydrogen is fixed but the utilisation of the station is being varied. It can be noted that lowering the utilisation rate for the tank station (Figure 22) affects the systems with centralised hydrogen production less, as the centralised hydrogen production costs in this analysis has been kept at the same level.

In the case where the capacity has been varied for both utilisation of the tank station and at the utilisation of the centralised hydrogen production all system solutions show the similar increase in cost when utilisation is lowered (see Figure 21).

For the sensitivity analyse case where the utilisation of the tank station has been varied but the hydrogen produced at a central site remain unchanged, the centralised production solutions show slightly less sensitivity towards lowered utilisation rate (see Figure 22).



Figure 21. Sensitivity analysis – Capacity utilisation variation. Results in SEK/kg for the eight calculated cases.



Figure 22. Sensitivity analysis – Hydrogen filling station utilisation rate variation. Results in SEK/kg for the eight calculated cases.

#### 6.4.4 Transport distance

Transport distance varied will only affect the centralised production cases (1a, 1b, 2a and 2b). When transport distance is varied the cost for hydrogen will increase slightly with increased transport distance for the central production solutions (see Figure 23). Decentralised production will not be affected by varied transport distance as the hydrogen is produced at site.



Figure 23. Sensitivity analysis - Transport distance. Results in SEK/kg for the eight calculated cases.

#### 6.4.5 Summary

Analysis by variation of investment costs shows that a large drop of costs on the investment side so that equipment dropped to the level of 40 % of today's estimated costs would bring the total cost level down some 10 %.

In case that costs for energy used as input to the process, specifically electricity and biogas became cheaper than the base case on a cost level of 40 %, the total costs could drop 45 % with lowered electricity price down to 40 SEK/kg for the decentralised electrolyser case.

The sensitivity analyses for the utilisation rate of the station gives a clear signal that the costs for running the system at a low utilisation rate will be unfavourable. The costs will be approximately doubled if the utilisation drops to 40 % of full capacity.

Transport distance will only affect the centralised production and for case 2b centralised reformer, a drop from the transport distance of 150 km down to 10 km will decrease the total costs some 5-6 %.

All in all, the sensitivity analysis shows that the estimations on costs are quite robust related to investments but sensitive to changes in the energy market (price of electricity, methane, and hydrogen). Sensitivity analyses also gives the reader a possibility to assess price development due to expected decrease for components related to development and economy of scale as well as related to expected price development on energy.

# 7 LIFE CYCLE ASSESMENT

The aim of the work presented in this section is to investigate the environmental performance and discuss potential benefits and limitations of the different scenarios. More specifically, we study the impact on climate change as an indicator for estimating the impact arising from emissions of greenhouse gases (GHG) as well as the overall energy efficiency the different systems. A well-to-tank (WTT) approach is adopted where the stages of hydrogen production, distribution and storage are considered.

# 7.1 METHODOLOGY

A short description and background to the methods used is provided below. Specific assumptions and methodological decisions in relation to the product system under evaluation are presented in Section 7.1.4.

## 7.1.1 LCA

Life cycle assessment (LCA) is a widely used method that quantifies the potential environmental impacts related to a product or a system during its whole life cycle i.e., from material extraction and manufacturing to use and end-of-life. A variety of standards and guidelines of how LCAs can be conducted is available (for example: ISO 14040 (ISO 14040:2006) and ISO 14044 (ISO 14044:2006).

An LCA normally contains four main steps:

- **Goal and scope definition** where the context and specific aim and boundaries of the study are defined.
- Life cycle inventory analysis where all necessary information regarding the flows of materials and resources to and from the studied system are collected.
- **Impact assessment** where flows of materials and substances are translated to environmental stressors.
- **Results interpretation** where the findings of the assessment are analysed, and improvement strategies are discussed.

Depending on the scope and context of the analysis, streamlined or product specific approaches can be applied. Streamlined approaches allow for simplifications in terms of system boundaries and process inclusion or in terms of impact assessment categories to be assessed. As the focus of this work has been to only look at the climate benefits, a simplified approach is applied, focusing, and presenting the results of the study only in terms of Climate Change or Global Warming Potential (GWP) (expressed in g  $CO_2$  eq.).

The calculations for estimating the climate benefits are performed using the commonly applied life cycle assessment methodology as described in ISO 14040/44 standard (ISO 14040:2006 and ISO 14044:2006) (referred to as ISO in the remaining of the report) and by applying the method proposed in the European Renewable Energy Directive (referred to as RED and REDII). Both approaches are described below:

#### 7.1.2 The Renewable Energy Directive (RED)

When it comes to transportation fuels, a commonly applied method for estimating their environmental impact in terms of climate change is provided by the Renewable Energy Directive (RED) (Directive 2009/28/EC). The Renewable Energy Directive commonly referred to as RED, is introduced by the EU, with the aim of reducing the GHG emissions of the energy and transport sector in order to meet the Paris Agreement goals and commitments while promoting the use of renewable fuels. Within RED, specific sustainability criteria and GHG emissions saving targets for biofuels and bioliquids are set.

The RED framework is not an LCA framework, but it has a life-cycle-based approach when considering the emissions of transportation biofuels, renewable fuels and electricity, heating and cooling. RED is used for reporting regulatory compliance and is therefore used in different contexts when transport fuels are assessed. It sets specific boundaries and provides concrete recommendations on how to deal with certain methodological questions to ensure harmonization and comparability of the results. In contrast to a full scale LCA, the scope of RED is limited to only selected environmental parameters i.e., mainly GHG emissions.

RED was firstly introduced in 2009 and has been in force up until now. In 2018, a recast of RED was published (Directive (EU) 2018/2001), known as RED II, where certain modifications and updates were considered. RED II is in force in Sweden since July 2021 (STEMFS (2021:7)). As there is a transition period where both RED and REDII are applicable and for consistency and comparability to previous studies, both versions are applied also in the present study. Differences among the two versions can be identified. Selected aspects that are of relevance of this work are listed in Table 1. Detailed documentation on the RED I & REDII methodologies can be found in the official publications from the EU (European Parliament, 2009; 2018).

The term "Biofuels" in RED indicates liquid or gaseous fuels for transport produced from biomass while in RED II "Biofuels" is used to denote only liquid fuels for transport produced from biomass. RED II further uses the term "Biomass fuels" to denote gaseous and solid fuels from biomass and "Biogas" to denote gaseous fuels produced from biomass.

In both RED and RED II, the calculations of GHG emissions from biofuels and bioliquids consider all life cycle stages from raw material production to the final use of the fuel according to the following formulas shown in Table 10.

	RED	RED II
GHG emissions formula (for biomass fuels)	$E^* = e_{ec} + e_{I} + e_{p} + e_{td} + e_{u} - e_{sca} - e_{ccs} - e_{ccr} - e_{ee}$	$E^{**} = e_{ec} + e_{I} + e_{p} + e_{td} + e_{u} - e_{sca} - e_{ccs} - e_{ccr}$
	E = total emissions from the production of the fuel. $e_{ec}$ = emissions from the extraction or cultivation of raw materials. $e_{I}$ = annualized emissions from carbon stock changes caused by land-use change. $e_{p}$ = emissions from feedstock processing. $e_{td}$ = emissions from transport and distribution. $e_{u}$ = emissions from the fuel in use. $e_{sca}$ = emission savings from soil carbon accumulation via improved agricultural management. $e_{ccs}$ = emission savings from carbon capture and geological storage. $e_{ccr}$ = emission savings from carbon capture and replacement. $e_{ee}$ = emission saving from excess electricity from cogeneration.	E = total emissions from the production of the fuel. $e_{ec}$ = emissions from the extraction or cultivation of raw materials. $e_{I}$ = annualized emissions from carbon stock changes caused by land-use change. $e_{p}$ = emissions from feedstock processing. $e_{td}$ = emissions from transport and distribution. $e_{u}$ = emissions from the fuel in use. $e_{sca}$ = emission savings from soil carbon accumulation via improved agricultural management. $e_{ccs}$ = emission savings from carbon capture and geological storage. $e_{ccr}$ = emission savings from carbon capture and replacement.
Use phase emissions	Emissions from the fuel in use, e <sub>u</sub> , shall be taken to be zero for biofuels and bioliquids.	Emissions of $CO_2$ from fuels in use (e <sub>u</sub> ) shall be zero for biomass fuels. However, emis- sions of $CH_4$ and $N_2O$ shall be included in the e <sub>u</sub> factor
Waste /Residues	Wastes and residues used as feedstock for biofuels production are considered burden free i.e., having zero GHG emissions up to their collection stage.	Wastes and residues used as feedstock for biofuels production are considered burden free i.e., having zero GHG emissions up to their collection stage.
Bonus for manure	N/A	For animal manure used as a substrate bio- gas production, a bonus of 45 g $CO_2$ eq./MJ manure (54 kg $CO_2$ eq./ t fresh matter) is added for improved agricultural and manu- re management.
Allocation principles for co products	Where a fuel production process produces, in com- bination, the fuel for which emissions are being calculated	Where a fuel production process produces, in combination, the fuel for which emis- sions are being calculated and one or more other

Table 10. Sel	ection of method	ological paramet	ers in RED an	nd RED II tha	at are of relevan	ce for this
work.						

\*As described in Annex V. Part C methodology (European Parliament 2009). RED did not provided details for the case of biogas or bio-methane (<u>http://data.europa.eu/eli/dir/2009/28/oj</u>).

\*\*As described in Annex VI. Part B methodology (European Parliament 2018). (<u>http://data.europa.eu/eli/dir/2018/2001/oj</u>).

#### 7.1.3 Energy efficiency indicator

The energy efficiency indicator estimated in this work considers the amount of energy entering the system as well as the energy leaving the system. The system boundaries in this case start with the feedstock material (biogas for the case of reformer or electricity for the case of electrolysis) while upstream processes for feedstock production are excluded. All energy flows are expressed on a lower heating value (LHV) basis. The generic formula considered is taken from (Poulikidou et al. 2019) and can be presented as follows:

$$\eta_{total} = \frac{\sum_{o} m_{o} * LHVo + Q^{-} + W_{el}^{-}}{\sum_{i} m_{i} * LHVi + Q^{+} + W_{el}^{+}}$$

where m representing mass flows, LHV lower heating value, Q heat flow and W<sub>el</sub> electricity streams. The subscripts and superscripts denote outputs (o, and "–") and inputs (i, and "+") respectively.

#### 7.1.4 Key assumptions and variations in the methods used

For all methods, an attributional approach based on average data collected for the relevant processes and fuels is applied. Certain methodological decisions, however, are of a consequential nature although no marginal data are used.

In the case of RED (RED & REDII), multi-output processes are handled through allocation based on the lower heating value (LHV) of the derived products. In the case of calculations following the ISO standard, multi-output processes are handled via system expansion and substitution both in the baseline and in the alternative scenarios assessed. Examples of such cases include the use of bio digestate obtained during biogas production (which is assumed to replacing mineral fertilizers) as well as the heat released at the electrolysis process (which is assumed to replacing heat in a district heating system).

The differences in approaches for handling co-products and the associated credits given, lead to variations in the product system studied. This is of high importance especially for the biogas production steps. In the case of RED biogas production accounts for all process impacts. No allocation is applied for instance for the rest product. In the case of RED II and ISO biogas production receives a credit from avoided emissions of manure storage while in the case of ISO, biogas production receives a credit from avoided mineral fertilizer. This approach is based on a similar study from Börjesson et al. (2016) where data were taken also for this work.

In all hydrogen production alternatives, the average Swedish electricity mix is used to model electricity demands in the baseline scenarios.

When it comes to the impact assessment stage, the characterization factors provided in RED and RED II are used for estimating the impact on climate change of the suggested pathways (presented also in Table 1). For the analysis based on the ISO standard, the characterization factors as applied in CML 2016 were used, which are the same as in RED II namely: 1 for  $CO_2$ , 25 for  $CH_4$  and 298 for N<sub>2</sub>O (IPCC 5<sup>th</sup> Assessment Report). The characterization factors used in RED, however, differ being 1 for  $CO_2$ , 23 for  $CH_4$  and 295 for N<sub>2</sub>O.

# 7.2 STUDIED SYSTEMS AND KEY INVENTORY DATA

The four different cases considered in this project and report are shortly described below. A more detailed description can be found in section 3. In all four cases, the system boundaries include the processes of feedstock production and acquisition (biogas or electricity), hydrogen production, hydrogen distribution (for the centralised cases) and hydrogen storage at filling station. The systems are assumed to produce and use of total of 50 GWh H<sub>2</sub> year. The hydrogen is supplied to end users at filling stations, where each filling station either handles 5 or 10 GWh H<sub>2</sub>/filling station & year

This chapter provides information on the inventory data in relation to the energy and material balances considered. Potential differences of the inventory data due to methodological variations among the three methods applied to this work namely RED, RED II and ISO, are noted when relevant. The inventory data are presented per functional unit i.e., **1 MJ of hydrogen at filling station.** 

Data in relation to the studied systems were obtained from the cost analysis in the project but also from literature. The LCA was modelled in GaBi (Sphera, 2021). Generic life cycle inventory datasets were used to model background processes.

## 7.2.1 Centralised hydrogen production

In the centralised cases, hydrogen is produced in central facilities and then distributed to the filling station via road transport. The process and inventory data for the two production pathways of the centralised cases water electrolysis and biogas reforming are presented below.

#### Alternative 1: Centralised hydrogen production via water electrolysis

Hydrogen produced in a central facility via water electrolysis corresponds to the reference case presented in this report. The life cycle stages and processes considered are illustrated in Figure 24 including hydrogen production, distribution, and hydrogen storage at filling station.



#### Figure 24. Process description of centralized hydrogen production via water electrolysis. For the baseline scenario, the heat released from the electrolysis step (grey box) is considered as waste heat thus no allocation is needed.

Inventory data used to model this case is provided in Table 11 based on data provided by the technoeconomic assessment performed in this project as well as literature data.

Туре	Process	Material	Amount		Unit	
Input			RED	REDII	ISO	
Raw	Electrolysis	Water feed	0.08	0.08	0.08	kg
material	Electrolysis	Electricity feed	1.47	1.47	1.47	MJ
Other material	Electrolysis	КОН	0.02	0.02	0.02	g
Energy	Electrolysis	Electricity auxiliary	0.14	0.14	0.14	MJ
Wares	Compression and low- pressure storage + compressor station	Electricity	0.04	0.04	0.04	MJ
	Transport of hydrogen	Biogas fuel	0.02	0.02	0.02	g
	Hydrogen filling station	Electricity	0.04	0.04	0.04	MJ
Water	Electrolysis	Cooling water	8.47	8.47	8.47	kg
Output			RED	REDII	ISO	
Main product	Hydrogen filling station	Hydrogen	1.00	1.00	1.00	MJ
Emissions to	Electrolysis	Heat	0.26	0.26	0.26	MJ
air	Electrolysis	Oxygen	0.07	0.07	0.07	kg

Table 11. Inventory data for the reference case:	Centralized hydrogen pr	oduction via water electro-
lysis.		

Electrolysis is performed using alkaline electrolyser (AEL). During electrolysis, water is electrochemically split into hydrogen and oxygen using electricity. The main inputs accounted to the electrolysis process is therefore electricity, water as well as auxiliary materials needed. AEL electrolyser is modelled based on data from (Koj, Wulf, Schreiber, & Zapp, 2017).

The electricity values during electrolysis include hydrogen purification and compression to 20 bar (a) as well as auxiliary power for water pumps, compression etc. Energy demand for cooling is assumed to be negligible. The assumed efficiency of the electrolysis process is 62 %. At the electrolysis step, heat is released. In the baseline scenarios, heat is modelled as waste heat i.e., not as co-product. Similarly, oxygen released from the processes is considered an emission. For this reason, no allocation is needed. The consecutive process steps during hydrogen production relate to adjustments of the pressure of the obtained gas thus requiring mainly electricity for their operation.

Distribution of compressed gas hydrogen  $(CGH_2)$  is performed by trucks in cylindrical steel or lowweight composite vessels, assuming a distance of 150 km. It is assumed that distribution is performed with biogas trucks. Data on fuel consumption and combustion were obtained from Prussi, Yugo, De Prada, Padella and Edwards, (2020). The emissions factors related to fuel combustion was based on Compressed Natural Gas (CNG) which was used as an approximation for the non- $CO_2$  related emissions. The chosen truck model is a long haul with a curb mass of 7,550 kg and a weighted payload of 14,290 kg. The production of biofuel (biogas) was based on data from Börjesson et al. (2016). Potential losses of hydrogen during hydrogen production are not considered.

#### Alternative 2: Centralised hydrogen production via reforming of bio-methane

In the second alternative assessed in this work, hydrogen is produced via steam bio-methane reforming (SMR), a process that imitates traditional hydrogen production via reforming of natural gas or other fossil-based resources and then distributed to the filling stations in truck containers. The life cycle stages and processes considered are illustrated in Figure 25 including the process of biogas production and upgrading at a central biogas facility, bio-methane reforming, hydrogen distribution and storage at filling station.



Figure 25. Process description of centralized hydrogen production via steam reforming of bio-methane (SMR). For the baseline scenario, the heat released from the reformer is not reused in the bio-methane production.

Inventory data used to model this case is provided in Table 12. The main input to the SMR process is bio-methane, electricity, and water (in the form of steam), where hydrogen is separated from the raw gas in multiple process steps. Carbon dioxide and residual heat are obtained apart from hydrogen. In the baseline scenario, it is assumed that there is no use for the carbon dioxide gas and the residual heat, which are released to the environment. For this reason, there is no need for allocation at this stage.

Туре	Process	Material	Amount			Unit
Input			RED	REDII	ISO	
Raw material	Bio-methane production (biogas plant)	Feedstock	0.80	0.80	0.80	kg
Other material	Reformer	Nitrogen	0.003	0.003	0.003	g
Energy Wares	Bio-methane production	Electricity	0.08	0.08	0.08	MJ
	Bio-methane production	Heat	0.14	0.14	0.14	MJ
	Bio-methane production	Diesel fuel	0.51	0.51	0.70	g
	Low pressure compression	Electricity	0.01	0.01	0.01	MJ
	Reformer	Electricity	0.05	0.05	0.05	MJ
	Compression + low-pressure storage and compressor station	Electricity	0.04	0.04	0.04	MJ
	Transport of hydrogen	Biogas fuel	0.02	0.02	0.02	g
	Hydrogen filling station	Electricity	0.04	0.04	0.04	MJ
Water	Reformer	Water	0.05	0.05	0.05	kg
Output			RED	REDII	ISO	
Main product	Hydrogen filling station	Hydrogen	1.00	1.00	1.00	MJ
Co-product	Bio-methane production	Digestate	0.00	0.00	0.42	kg
	Bio-methane production	Methane	0.21	-0.35	-0.35	g
Emissions to	Bio-methane production	Nitrous oxide	0.00	-0.01	-0.01	g
air	Bio-methane production	Carbon dioxide	0.00	0.00	-1.93	g
	Reformer	Methane	0.02	0.02	0.02	g

Table 12. Inventory data for alternative: Centrali	ed hydrogen production	via steam bio-methane re-
forming (SMR).		

Data for biogas production are obtained from Börjesson et al. (2016). The feedstock to the biogas facility consisted of food waste (21.5%), manure (39.5%), industrial waste (28.4%) and slaughterhouse waste (10.6%). The feedstock is assumed to be transported 20 km to the biogas facility. During biogas production, digestate is obtained that is assumed to replaces mineral fertilizer when it comes to the ISO methodology (see also assumptions presented in section 7.1.4). A difference among the inventory data related to the three methods considered (RED, REDII and ISO) is that RED II and ISO include a credit for the avoided methane emitted during manure storing and spreading (see also Table 10), therefore a net negative value is obtained.

Similarly, to alternative 1, distribution of compressed gas hydrogen  $(CGH_2)$  is performed by trucks in cylindrical steel or low-weight composite vessels, assuming a distance of 150 km. It is assumed that distribution is performed with biogas trucks. Data on the emissions factors from biogas production and combustion as transport fuel were obtained from Prussi et al., (2020).

#### 7.2.2 Decentralised hydrogen production

In the decentralised alternatives, hydrogen is produced at the filling station from electrolysis of water or reforming of biogas. Water is transported to the filling station in water pipelines and biomethane is transported to the filling station in gas pipeline or by road transport. The process and inventory data for the two production pathways of the decentralised cases, water electrolysis and bio-methane reforming, are presented below.

#### Alternative 3: Decentralised hydrogen production via water electrolysis

Hydrogen in this alternative is produced at the filling station via water electrolysis. The life cycle stages and processes considered are illustrated in Figure 26 including hydrogen production, and hydrogen storage at filling station.



Figure 26 Process description of decentralised hydrogen production via water electrolysis. For the baseline scenario, the heat released from the electrolysis step is considered as waste heat thus no allocation is needed.

Inventory data used to model this case is provided in Table 13. The electrolysis step is the same as in alternative 1. The difference of this alternative compared to alternative 1 is primarily the distribution stage that is no longer required.

Туре	Process	Material	Amount			Unit
Input			RED	REDII	ISO	
Raw material	Electrolysis	Water feed	0.08	0.08	0.08	kg
	Electrolysis	Electricity feed	1.47	1.47	1.47	MJ
Other material	Electrolysis	КОН	0.02	0.02	0.02	g
Energy Wares	Electrolysis	Electricity auxiliary	0.14	0.14	0.14	MJ
	Electrolysis	Electricity cooling*	0.00	0.00	0.00	MJ
	Compression and low-pressure storage + compressor station	Electricity	0.04	0.04	0.04	MJ
Water	Filling station	Electricity	0.05	0.05	0.05	MJ
Output			RED	REDII	ISO	
Main product	Hydrogen filling station	Hydrogen	1.00	1.00	1.00	MJ
Emissions to	Electrolysis	Heat	0.26	0.26	0.26	MJ
air	Electrolysis	Oxygen	0.07	0.07	0.07	kg

Table 13. Inventory data for alternative: Decentralised hydrogen production via water electrolysis.

\*Electricity consumption for cooling is negligible.

#### Alternative 4: Decentralised hydrogen production via reforming of bio-methane

In this alternative, hydrogen is produced via steam bio-methane reforming (SMR) at the filling station. The life cycle stages and processes considered are illustrated in Figure 27 including the process of biogas production and upgrading to bio-methane at a central biogas facility, transport of bio-methane to the filling station, bio-methane reforming to produce hydrogen and storage at filling station.



Figure 27 Process description of decentralised hydrogen production via steam reforming of biomethane (SMR). For the baseline scenario, the heat released from the reformer is not reused in the biomethane production.

In the baseline scenario, bio-methane is assumed to be transported to the filling station in gas form by truck in containers<sup>5</sup>. An average distance of 150 km is assumed while the fuel used in the trucks is also biogas. Data on the emissions factors from biogas production and combustion were obtained from Prussi et al., (2020).

For the reforming process, the same input data as shown in Table 12 are assumed. Complete data for this alternative are shown in Table 14.

<sup>&</sup>lt;sup>5</sup> Alternative transport pathways in liquid form with tank truck or in compressed form (low pressure) by gas pipeline are considered in the scenario analysis (see section 7.2.3).

Туре		Process		Material		Amount			Unit
Input						RED	REDII	ISO	
Raw material		Bio-methane production (biogas Fe		Feedstock		0.80	0.80	0.80	kg
Other material		Reformer		Nitrogen		0.003	0.003	0.003	g
Energy Wares		Bio-methane production		Electricity		0.08	0.08	0.08	MJ
		Bio-methane production		Heat		0.14	0.14	0.14	MJ
		Bio-methane production		Diesel fuel		0.51	0.51	0.70	g
		Bio-methane compression		Electricity		0.04	0.04	0.04	MJ
		Transport of bio-methane		Biogas fuel		0.08	0.08	0.08	g
		Reformer		Electricity		0.05	0.05	0.05	MJ
		Compression + low-pressure storage and compressor station		Electricity		0.04	0.04	0.04	MJ
		Hydrogen filling station		Electricity		0.05	0.05	0.05	MJ
Water		Reformer		Water		0.05	0.05	0.05	kg
Output						RED	REDII	ISO	
Main product	Нус	drogen filling station	Ну	/drogen	1.00 1.	00 1.00	MJ		
Co-product		Bio-methane production		Digestate		0.00	0.00	0.42	kg
		Bio-methane production		Methane		0.21	-0.35	-0.35	g
Emissions to ai	r	Bio-methane production		Nitrous oxi	de	0.00	-0.01	-0.01	g
		Bio-methane production		Carbon dio	xide	0.00	0.00	-1.93	g
Reformer	Methan	ne 0.02	0.02	0.02	g				

Table 14. Inventory data for alternative: Decentralised hydrogen production via steam bio-methane reforming (SMR).

# 7.2.3 Scenario analysis

In addition to the baseline alternatives presented above, different scenarios have been investigated to assess opportunities and improvement potentials of the suggested pathways. The scenarios are listed in Table 15 below together with the respective assumptions considered for the baseline cases. The scenarios considered concern changes in co-products handling, distribution alternatives as well as the electricity source.

Production pathway	Baseline scenario	Scenario A	Scenario B	Scenario C
Alternative 1: Centralized hydrogen production via water electrolysis	Swedish electricity mix Heat released to the environment	Swedish electricity mix Heat released considered a co- product substituting heat in the district heating system.	No change compared to baseline	Comparison of different electricity alternatives including renewable electricity from wind, Nordic Average Grid mix and European Average Grid mix (EU- 28). No other change compared to baseline
Alternative 2: Centralized hydrogen production via steam reforming of bio-methane	Swedish electricity mix Heat released to the environment	Swedish electricity mix Heat circulated back to the biogas facility reducing the demand of biomass-based heat.	No change compared to baseline	Comparison of different electricity alternatives including renewable electricity from wind, Nordic Average Grid mix, European Average Grid mix (EU- 28). No other change compared to baseline
Alternative 3: Decentralized hydrogen production via water electrolysis	Swedish electricity mix Heat released to the environment	No change compared to baseline	No change compared to baseline	Comparison of different electricity alternatives including renewable electricity from wind, Nordic Average Grid mix, European Average Grid mix (EU- 28). No other change compared to baseline
Alternative 4: Decentralized hydrogen production via steam reforming of bio-methane	Swedish electricity mix Heat released to the environment	No change compared to baseline	Swedish electricity mix Alternative transport pathways in liquid form with tank truck or in compressed form by gas pipeline	Comparison of different electricity alternatives including renewable electricity from wind, Nordic Average Grid mix, European Average Grid mix (EU- 28). No other change compared to baseline

Table 15. Summary	0	scenarios assessed	in	this	work	including	the	baseline	scenario.
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In scenario A, for alternative 1 (central hydrogen production via water electrolysis) the heat that is released from the process is now considered as a co-product. This leads to the electrolysis being a multifunctional process. To account for the impact of hydrogen production only, energy-based allocation is used when it comes to RED method (RED and REDII). The updated inventory data for this case are listed in Table 16 where values in bold highlight the differences to the baseline values. In the case of ISO, system expansion and substitution are applied, therefore we consider that the heat released will replace and equivalent amount of heat produced in the district heating network. The district heating network is modelled based on earlier work by IVL. According to the model, more than 44% of the fuel mix consists of wood biomass while 25% comes from waste. The impact on climate change is calculated to  $0.044 \text{ kg CO}_2 \text{ eq./kWh}$ . Moreover, and for the alternative 2, sce-

nario A assumes that the heat that is released during the digestion process can be recirculated and reduce the needs for external heat (data shown in Table 17).

Туре	Process	Material Amount		int		Unit
Input			RED	REDII	ISO	
Raw material	Electrolysis	Water feed	0.06	0.06	0.08	kg
	Electrolysis	Electricity feed	1.17	1.17	1.47	MJ
Other material	Electrolysis	КОН	0.02	0.02	0.02	g
Energy Wares	Electrolysis	Electricity auxiliary	0.11	0.11	0.14	MJ
	Compression and low-pressure storage + compressor station	w-pressure storage + Electricity		0.04	0.04	MJ
	Transport of hydrogen	Biogas fuel	0.02	0.02	0.02	g
	Hydrogen filling station	Electricity	0.04	0.04	0.04	kg
Water	Electrolysis	Cooling water	6.74	6.74	8.47	kg
Output			RED	REDII	ISO	
Main product	Hydrogen filling station	Hydrogen	1.00	1.00	1.00	MJ
Co-product (former emissions to air)	Electrolysis	Heat	0.00	0.00	0.26	MJ
Emissions to air	Electrolysis	Oxygen	0.05	0.05	0.07	kg

 Table 16. Centralised hydrogen production via water electrolysis - Scenario A.

Туре	Process Materia		Amour	nt		Unit
Input			RED	REDII	ISO	
Raw material	Bio-methane production	Feedstock	0.80	0.80	0.80	kg
Other material	Reformer	Nitrogen	0.003	0.003	0.003	g
Energy Wares	Bio-methane production	Electricity	0.08	0.08	0.08	MJ
	Bio-methane production	Heat	0.09	0.09	0.09	MJ
	Bio-methane production	Diesel fuel	0.51	0.51	0.70	g
	Low pressure compression	Electricity	0.01	0.01	0.01	MJ
	Reformer	Electricity	0.05	0.05	0.05	MJ
	Compression + low-pressure storage and compressor station	Electricity	0.04	0.04	0.04	MJ
	Transport of hydrogen	Biogas fuel	0.02	0.02	0.02	g
	Hydrogen filling station	Electricity	0.04	0.04	0.04	MJ
Water	Reformer	Water	0.05	0.05	0.05	kg
Output			RED	REDII	ISO	
Main product	Hydrogen filling station	Hydrogen	1.00	1.00	1.00	MJ
Co-product	Bio-methane production	Digestate	0.00	0.00	0.42	kg
	Bio-methane production	Methane	0.21	-0.35	-0.35	g
Emissions to	Bio-methane production	Nitrous oxide	0.00	-0.01	-0.01	g
air	Bio-methane production	Carbon dioxide	0.00	0.00	-1.93	g
	Reformer	Methane	0.02	0.02	0.02	g

Table 17. Centralised hydrogen production via steam reforming of biogas (SMR) - Scenario A.

In scenario B, the difference to the baseline case concerns only alternative 4 and the decentralised production of hydrogen via reforming. In this scenario, upgraded biogas can be either transported to the filling station and reformer via a gas pipeline (data presented in Table 18) or by trucks in liquid form (LBG) (data shown in Table 19). This reduces the need for transport in the decentralised case though certain modifications in terms of pressure and temperature adjustments can occur that lead to additional electricity demands.

Туре	Process	Material	Amount			Unit
Input			RED	REDII	ISO	
Raw material	Bio-methane production	Feedstock	0.80	0.80	0.80	kg
Other material	Reformer	Nitrogen	0.003	0.003	0.003	g
Energy Wares	Bio-methane production	Electricity	0.08	0.08	0.08	MJ
	Bio-methane production	Heat	0.14	0.14	0.14	MJ
	Bio-methane production	Diesel fuel	0.51	0.51	0.70	g
	Bio-methane compression	Electricity	0.01	0.01	0.01	MJ
	Transport of bio-methane	Biogas fuel	0.00	0.00	0.00	g
	Reformer	Electricity	0.05	0.05	0.05	MJ
	Compression + low-pressure storage and compressor station	Electricity	0.04	0.04	0.04	MJ
Water	Hydrogen filling station	Electricity	0.05	0.05	0.05	MJ
Output	Reformer	Water	0.05	0.05	0.05	kg
Main product			RED	REDII	ISO	
Co-product	Hydrogen filling station	Hydrogen	1.00	1.00	1.00	MJ
	Bio-methane production	Digestate	0.00	0.00	0.42	kg
Emissions to air	Bio-methane production	Methane	0.21	-0.35	-0.35	g
	Bio-methane production	Nitrous oxide	0.00	-0.01	-0.01	g
	Bio-methane production	Carbon dioxide	0.00	0.00	-1.93	g
	Reformer	Methane	0.02	0.02	0.02	g

Table 18. Decentralized hydrogen production via steam reforming of biogas (SMR) - Scenario B (Grid).

Туре	Process	Material	Amount		Unit	
Input			RED	REDII	ISO	
Raw material	Bio-methane production	Feedstock	0.80	0.80	0.80	kg
Other material	Reformer	Nitrogen	0.003	0.003	0.003	g
Energy Wares	Bio-methane production	Electricity	0.08	0.08	0.08	MJ
	Bio-methane production	Heat	0.14	0.14	0.14	MJ
	Bio-methane production	Diesel fuel	0.51	0.51	0.70	g
	Bio-methane compression	Electricity	0.08	0.08	0.08	MJ
	Transport of bio-methane	Biogas fuel	0.07	0.07	0.07	g
	Reformer	Electricity	0.05	0.05	0.05	MJ
	Compression + low-pressure storage and compressor station	Electricity	0.04	0.04	0.04	MJ
Water	Hydrogen filling station	Electricity	0.05	0.05	0.05	MJ
Output	Reformer	Water	0.05	0.05	0.05	kg
Main product			RED	REDII	ISO	
Co-product	Hydrogen filling station	Hydrogen	1.00	1.00	1.00	MJ
	Bio-methane production	Digestate	0.00	0.00	0.42	kg
Emissions to air	Bio-methane production	Methane	0.21	-0.35	-0.35	g
	Bio-methane production	Nitrous oxide	0.00	-0.01	-0.01	g
	Bio-methane production	Carbon dioxide	0.00	0.00	-1.93	g
	Reformer	Methane	0.02	0.02	.0.2	g

 Table 19. Decentralized hydrogen production via steam reforming of biogas (SMR) - Scenario B (LBG).

Finally, scenario C, is based on the same process assumptions as in the baseline scenarios for all alternatives with the difference that electricity is supplied by different sources. A 100% renewable source, such as wind is modelled and compared to the Nordic Average Grid mix as well as the European Average Grid mix based on the datasets obtained from Sphera (2021).

# 7.3 CLIMATE CHANGE INDICATOR

The environmental performance of the four hydrogen production alternatives investigated in this work is presented in Figure 28following illustrating also the different values obtained when the three different methodological approaches where used (i.e., RED/REDII and ISO). The environmental impact is assessed in terms of climate change expressed in g  $CO_2$  eq. per MJ hydrogen at filling station. The results presented here refer to the baseline scenarios that apart from the digestate and manure credit, no other co product allocation or benefit is considered.

As shown from the figure, the obtained results vary from -7 g  $CO_2$  eq. per MJ hydrogen to 19 g  $CO_2$  eq. per MJ hydrogen, depending on the pathway and method followed. The environmental performance of hydrogen production using water electrolysis amounts to 19 g  $CO_2$  eq. per MJ hydrogen, with very small variations among the central and decentralized production. The electrolysis step accounts for the vast majority of the environmental impact despite the fact that the Swedish electricity mix has a relatively low carbon emission factor (ca 40 g  $CO_2$  eq. per kWh).

Similarly, the comparison between the centralized and decentralized hydrogen production via biomethane reforming show small variations with the total impact being between 11.4 to 11.7 g  $CO_2$  eq. per MJ hydrogen (for the RED method and when no credit for manure handling is considered) to -7 g  $CO_2$  eq. per MJ hydrogen when the benefits of digestate are taken into consideration (ISO methods). The share of biogas production dominates the result, leading also to the greater emission savings (as noted in REDII and ISO estimations).



Figure 28. Results illustrating the climate change indicator (expressed in g  $CO_2$  eq. per MJ hydrogen at filling station) for the different hydrogen production pathways investigated in this report. The numbers on each bar indicate the total or net impact in case of negative emissions.

Comparing the four different alternatives, hydrogen production via bio-methane reforming pathway remains the alternative with the lowest impact. In the recast of the renewable energy directive (referred to as RED II) however, a credit for avoided methane emissions from manure is attributed to the biogas generating system using manure as feedstock and therefore the total impact is significantly lower. Considering avoided emissions from co-products indicate further emission savings.

# 7.4 SCENARO ANALYSIS

The results from the additional scenarios (noted as A; B and C) are illustrated in the figures below. Figure 29 presents the results from scenario A where in contrast to the base line scenario, the heat released at the central hydrogen production facility is substituting heat from the district heating system while in the case of bio-methane reforming, it substitutes part of the external heat demand to the biogas production process. For both systems, the climate impact is reduced although slightly higher emission savings are demonstrated to the electrolysis pathways where the climate impact



indicator is reduced to 15.3-16 g  $CO_2$  eq. per MJ hydrogen depending on the LCA method considered.

# Figure 29. Results illustrating the difference of the baseline scenario to scenario A. The figure on the left presents results of the electrolysis pathways while the figure on the right presents the results of the bio-methane reforming pathways. The numbers on each bar indicate the total or net impact in case of negative emissions.

Scenario B investigated different bio-methane distribution options for the decentralized hydrogen production pathway. Transport of bio-methane to the reformer at the filling station can be performed in gas form in trucks (baseline) or via the gas network or in liquid form (scenario B). It can be seen from the results presented in Figure 30, that no significant change on the total amount of GHG emissions is observed. Transporting of bio-methane via the gas network (grid) can be a slightly better alternative while liquefying bio-methane can lead to additional emissions which offsets the savings from the decreased need for transports in comparison to compressed biogas.



Figure 30. Results illustrating the difference of the baseline scenario to scenario B when the decentralized hydrogen production via bio-methane reforming is considered. The numbers on each bar indicate the total or net impact in case of negative emissions.

In the last scenario, scenario C the baseline assumptions are considered for all studied systems with the difference that the Swedish electricity mix is substituted by alternative electricity mixes including electricity from wind power but also the Nordic or European average mixes. This scenario is of great relevance to the electrolysis pathways where electricity dominates the total GHG emissions. As shown in Figure 31, a reduction of 84% on the total GHG emissions is obtained compared to the baselines leading to a total impact that ranges from  $3.4 \text{ g CO}_2$  eq. per MJ hydrogen (depending on the LCA method considered) when wind power is used. On the contrary the GHG emission levels become significantly higher when the EU electricity mix is considered (see Figure 32).


Figure 31. Results illustrating the difference of the baseline scenario to scenario C when the hydrogen production via electrolysis is considered with wind power electricity. The central hydrogen production pathway is shown in the left figure while the decentralised pathway in the right. The numbers on each bar indicate the total impact.

Although relevant from a systems perspective, the emissions reduction levels for the case of biomethane reforming alternatives are much lower. This can be also due to the fact that the Swedish electricity mix has a relatively low emission factor. Looking to the cases where the alternative electricity mixes are studied (Nordic or European Average Grid mixes) the difference is sharper as illustrated in Figure 32.



Figure 32. Results illustrating the difference of the baseline scenario to scenario C where the following electricity mixes are considered: Swedish National Grid Mix (SE-Grid), Swedish Wind Power (SE – Wind), Nordic Average Electricity Grid Mix (Nordic) and European Average Electricity Grid Mix (EU-28).

## 7.5 ENERGY EFFICENCY INDICATOR

In terms of energy efficiency, the different pathways demonstrate a similar performance, all above 55%. Alternatives 1 and 3, central and decentral hydrogen production via electrolysis, obtained the lower efficiency factor, 58% and 59% respectively. Hydrogen production via steam bio-methane

reforming obtained higher rates of 68%. In both cases however, primary energy for the production of the raw material, electricity and biogas respectively is not considered something that is expected to lower the overall efficiency indicators of both systems. On the other hand, and by considered the excess heat that can be utilised, the efficiency rates of the electrolysis pathways can be expected to increase to 73%.

## 8 DISCUSSION AND CONCLUSIONS

## 8.1 DISCUSSION

The concept of a multi filling station includes the provision of multiple fuels at a single point of fuelling. However, this is not the sole purpose of the concept. Instead, a multi filling station may enable the gradual market introduction of a novel fuel based on the infrastructure and distribution network of an existing ditto. The novel fuel, being hydrogen produced at the site of fuelling, like in the several of the cases described in this study, may draw several benefits from this concept:

- Firstly, the establishment of hydrogen as a vehicle fuel can be introduced gradually at the fuelling station, potentially minimizing investment costs for capacity determining infrastructure such as storage, compressors and dispensers.
- Secondly, this potentially also minimizes costs and risks for the hydrogen filling station investment itself but also for commercial actors considering investing in hydrogen vehicles, as the supply of hydrogen may be scaled with demand through the concept of multi filling stations.
- The third benefit, namely possibly avoiding the chicken-and-egg catch; that vehicles need filling stations to work, and filling stations need vehicles to fuel there to be profitable.
- Another possible benefit with the multi filling station concept is that when establishing a hydrogen station at a filling station for CBG already present, the time from decision to realization of the hydrogen fuelling station can be considerably shorter. This is due to the elimination of novel site scouting, examination, and preparation, and also due to the reduced permission processing times associated with station expansion compared to green field establishment. Moreover, the most attractive sites for filling station in general are often already occupied by existing ditto and co-locating with such a station hence enables a more accessible location for hydrogen as a fuel. This in-turn also has the potential benefit of reducing the time needed for the drivers to locate a station and fuel their vehicles.

The multi filling station concept was evaluated in this study based on four system solutions: *central electrolysis*, *central reforming*, *decentralised electrolysis*, and *decentralised reforming*. The former two requiring transport of hydrogen between the site of production to the site of consumption, while the latter two instead rely on already established distribution of bio-methane All four production systems are evaluated for supplying to different sizes of hydrogen refuelling stations (5 resp. 10 GWh H<sub>2</sub> annually), thus totalling the count of compared systems to eight different setups.

For technoeconomic considerations, the production cost of hydrogen for the eight systems is the key parameter. The production cost for hydrogen at fuelling was determined based on the calculation model developed within this study, for each system. Based on the preconditions specified above in the report, the results are discussed in this chapter of the report. The results depend on CAPEX and OPEX for the complete systems from production to fuelling and includes distribution when applicable. The cheapest option was the decentral electrolyser-based system for the larger (10 GWh H2/year) capacity filling station with a production cost of around 75 SEK per kg of H<sub>2</sub> which equals 2,25 SEK/kWh. The most expensive system-options were central reformer, decentral reformer, and central electrolyser, all with the smaller 5 GWh H<sub>2</sub>/year filling station capacity and all reaching a production cost of around 100 SEK per kg H<sub>2</sub> which equals 3 SEK/kWh. In general, it

can be concluded that the systems with the smaller production capacity are more expensive in terms of cost per kg  $H_2$ , and electrolyser-based systems are cheaper compared to reformer-based ditto. It is important to stress that this result is strictly techno-economical and does not take environmental considerations into account. The results may be different than the results on climate impacts from the life-cycle analysis of the same systems.

Within the progression of this project, several meetings have been held with the reference group of the project. In the discussions of those meetings, it has become increasingly clear that this group considers the "golden number" of hydrogen cost at the filling station to be in the vicinity of 50 SEK per kg H<sub>2</sub>, representing a level of cost-competitive production compared to other fuel options. Thus between 50 and 33 % smaller than the results from this study. This golden number is deemed to represent a cost-level where business cases of using hydrogen as a vehicle fuel starts to make sense from an economical perspective. In other words, the TCO for a hydrogen vehicle looks better relative to other powertrains if the price of hydrogen is 50 SEK per kg H<sub>2</sub> which equals 1,5 SEK/kWh.

One way to look at it would be to subtract the costs for the filling station as well as the costs for any transportation for hydrogen needed to the station from the total cost for hydrogen. Such calculation gives that a fully utilised filling station including distribution of hydrogen without any production costs sums up to approximately 35 SEK/kg. That means that hydrogen purchased at a cost level below 15 SEK/kg which equals 0,45 SEK/kWh would meet the cost level of 50 SEK/kg hydrogen.

One way of solving that equation would be to find hydrogen produced centralised at a cost level below 15 SEK/kg. Given an equivalent investment and operating cost as the base case, it probably is required that the hydrogen filling station is co-located together or close by with a large consumer of hydrogen and that the produced oxygen or carbon dioxide and waste heat are utilized and generates revenue.

Another way of hitting a price below 50 SEK/kg would be if the total investments where 65% of the base case estimates together with an electricity price including taxes at 0,65 SEK/kWh instead of 1,00 SEK/kWh (base case). In such case the 3b option with decentralised electrolyser would meet that target.

In general, a drastic reduction in the investment costs for electrolysers and, maybe to a lesser extent, reformers seem possible within the decade, based on slight extrapolation from recently published statistics (e.g., (IEA, The Future of Hydrogen, 2019; Fuel Cells and Hydrogen Joint Undertaking, n.d.; Christensen, 2020; IRENA, 2018). Another option would be co-localizing a hydrogen production plant with an industry with a need for both hydrogen, oxygen and residual heat. As for many capital and operational cost-intensive investments, scale and utilisation rate is imperative. Such a system-solution is outside of the scope of this study but nevertheless could potentially provide incentives needed for reaching considerably lower overall production costs if the excess hydrogen may be provided as vehicle fuel. This kind of large-scale production units may also open the door to hydrogen pipeline-solutions with a high CAPEX but lower OPEX, thus being economically defendable for a large-scale, high utilisation rate production unit. Moreover, the costs can be even lower given that the filling station is also co-located with such a plant, however, this limits the number of possible implementation sites quite drastically. For CAPEX, it is rather safe to state that technological development will continue to drive costs down for the equipment needed to build the systems described in this study. Related to OPEX however, the crystal ball is a bit foggier. Energy prices will most likely continue to fluctuate over time, possibly with an increase in both frequency and amplitude of the fluctuations due to the increased intermittency of the energy production systems. Thus, making the OPEX-side of production cost less easy to predict and possibly translating to modular systems becoming more attractive, given their scalability in production volume and their less severe dependence on high utilisation rate, compared to large place build installations.

The sensitivity analyses made, by variating a selected number of cost parameters, shows that costs for energy input (electricity/biogas) as well as investments costs affects the total costs significantly. Also, the utilisation rate in form of total produced and delivered amount of hydrogen per system or per tank station, in relation to maximum capacity has a large impact on total costs. Transport distance of hydrogen from a centralised production plant is important but not to the same extent.

The environmental performance of hydrogen production systems from a variety of technologies has been previously assessed by several authors (Bhandari et al., 2014; Börjesson et al., 2016; Burkhardt, Patyk, Tanguy, & Retzke, 2016; Fredershausen et al., 2021; Wulf & Kaltschmitt, 2012, Wulf & Kaltschmitt, 2018, Prussi et al., 2020). Wulf & Kaltschmitt (2018) estimated an impact of 7 g  $CO_2$  eq./MJ for AEL hydrogen production for a decentralized scenario and by assuming windbased electricity. In the same study, the bio-methane reforming pathway demonstrates an impact of 37 g  $CO_2$  eq./MJ that is considerably higher than the emissions obtained in this work in the baseline scenario. The main reasons behind this difference is the feedstock mix used in the biogas facility that includes energy crops, as well the electricity mix assumed (German mix).

In the updated JEC v5 report by Prussi et al., (2020), the GHG emissions of hydrogen produced via electrolysis vary from 200 to over 400 g CO<sub>2</sub> eq per MJ hydrogen when fossil fuels such as coal or natural gas are used. Their results also vary significantly depending on the electricity source and process assumed (centralized or decentralized facilities). For wind-based electricity the values obtained are in the same range as in this work i.e., between 3-9 g CO<sub>2</sub> eq per MJ hydrogen. Hydrogen produced via bio-methane reforming is also presented in the aforementioned report, demonstrating significant variations among the feedstocks are used for the production of bio-methane. In comparison to other biofuels, the climate impact of hydrogen as presented in this work can be similar (when produced via electrolysis) or even lower (when produced from biogas) than HVO, methanol or other gaseous fuels when they are also produced from renewable or waste based sources. The GHG performance of DME for instance ranges between 10-18 g CO<sub>2</sub> eq per MJ when produced from wood or 1.7 g CO<sub>2</sub> eq per MJ when produced from renewable electricity as presented by Prussi et al., (2020).

The availability and supply of sustainable feedstocks for biogas production (i.e., feedstocks based on waste or residue streams) is highlighted as an important factor for low GHG emissions of hydrogen production via this route. Although concerns about resource availability are often raised, recent studies show that the biogas potential of manure and other organic residues for biogas production in Sweden is 6-8 TWh year 2030 as well as in the year 2045 (Börjesson, 2021).

Similarly, renewable electricity as an energy source for hydrogen production in the electrolysis route is a determining factor for low emissions values to be achieved as many studies presented

also previously. Another determining factor can be the possibilities for off-setting of the co-products from the water electrolysis process. In this work and in the baseline scenario in particular, all impact of the electrolysis step is allocated to the produced hydrogen. As heat and oxygen can be considered co- products the overall impact of hydrogen production, at least in the centralized scenario, could be lower as it will be allocated to all three outputs. In this work we have considered the utilization of heat but not oxygen due to more uncertainties. Several authors however have identified potential uses of that oxygen while some industrial examples are also available such as in the metal or chemicals making industry or in medicine.

A final note is that centralized production systems are the systems with the higher potential for coproducts utilization thus for improving the overall impact and energy efficiency of the process.

The benefit of reforming bio-methane instead of directly using bio-methane to power a truck is that it is easier to capture carbon dioxide at a point source (at the site of the reformer) instead of from a moving vehicle. This means that in the centralised case, the carbon dioxide that is produced during bio-methane reforming can be captured together with the carbon dioxide that is produced when biogas is upgraded to bio-methane. The carbon dioxide that should be relatively pure can then after purification be used in a Carbon Capture and Utilization process or Carbon Capture and Storage process.

However, producing hydrogen and capture carbon dioxide at a decentralised location such as a biomethane filling station means that the amount of hydrogen and carbon dioxide that can be produced at the station is limited by how much bio-methane that can be stored at the station in compressed or liquid form. For a bio-methane filling station that is connected to the natural gas network, there is no such restriction, but the flow in the natural gas network is instead a limiting factor.

## 8.2 CONCLUSIONS

In general, it can be concluded that the systems with the smaller capacity are more expensive in terms of cost per kg H<sub>2</sub>, electrolyser-based systems are cheaper compared to reformer-based ditto and that decentralised systems is less expensive in terms of cost per kg H<sub>2</sub> compared to the centralised counterpart. It is important to stress that this result is strictly techno-economical and does not take environmental considerations into account. The results may be different than the results on climate impact from the life-cycle analysis of the same systems. In terms of influencers for overall production costs for hydrogen, price for electricity and biogas are the strongest contributors, for electrolyser- and reformer-based production, respectively.

The cost curve (EUR/kW<sub>el</sub>) for electrolysers is relatively flat for capacities over 2 MWel, which corresponds to around 10 GWh annually. The same hold true for SMR above 30 kg  $H_2$ /h for modular systems and above 75  $H_2$ /h for non-modular ditto. This makes the economy of scale for centralised production limited compared to decentralised production for the larger type of filling station 10 GWh/year. Compared to the smaller filling station option (5 GWh/year), economy of scale is clearer.

The centralised options require some additional equipment (more compressors, and auxiliary equipment on the terminal) as well as additional ground preparations. Since the decentralised filling stations still are quite large in comparison to the central production facilities, economy of scale

does not surpass the additional costs. If the decentralised filling stations would be smaller, central production would become a more economically attractive option, in relative terms. Hence, it is not evident that an even larger centralised production facility would entail considerable cost-savings on the production side due to: i) The benefits of a larger electrolyser or reformer facility is limited (as discussed above), ii) The specific costs related to storage is in principle constant, and iii) the specific costs for the compressor admittedly declines relatively fast as capacity grows, but at some point a maximum capacity for a single unit is reached whereafter multiple units will be installed in parallel instead, thus in-effect causing the specific cost to become constant instead.

The assessments of costs are valid currently. For certain components, the costs can probably be lowered relatively quickly in the future through increased production volumes and associated economy of scale in number of units produced. This probably applies to hydrogen compressor units and electrolysers, possibly also to hydrogen storage facilities.

Lack of economies of scale, low individual station capacities, low utilisation rates and relatively high cost of components means that the refuelling stations currently typically account for a significant share of the cost of hydrogen at the dispenser. While all the components that make up a station are commercially available cost reductions can be expected with higher market penetration including costs related to dispensers, compressors, controls and safety equipment. Learning and economies of scale could also be expected to increase reliability and lower maintenance costs.

Hydrogen has been widely discussed as an alternative that will enhance the transition of the transport sector from fossil based to renewable and low polluting fuels and technologies. Having generally a low impact during the use phase, at least in terms of carbon and other regulated emissions, the shift of the focus towards hydrogen production and distribution is essential to ensure emission reductions from a life cycle perspective and avoid trade-offs.

In this work, two different production alternatives (hydrogen via water electrolysis and by biomethane reforming) and distribution scenarios (central and decentral) were assessed, where the aim was to quantify and compare their environmental impacts in terms of greenhouse gas emissions.

The GHG emissions of the assessed alternatives range from -7 g  $CO_2$  eq. per MJ hydrogen to 19 g  $CO_2$  eq. per MJ hydrogen, depending on the LCA framework used for the baseline scenarios. Depending on the improvement strategy considered (i.e., use of heat, distribution via gas network or renewable electricity), significant reductions were estimated. The higher emission reductions were obtained where electricity from wind power was used for the electrolysis pathways reducing the impact from hydrogen production from 19 to 3.4 g  $CO_2$  eq. per MJ (i.e., an 84% reduction).

The findings of the study indicate that steam reforming of biogas is the alternative with the lowest net emissions. This is mainly due to the low impact of biogas especially when waste and residues are used as feedstock and when co-products from biogas production can be used to replace fossil alternatives (such as mineral fertilizers). Hydrogen produced via electrolysis is an energy intense alternative. It would be a more competitive alternative if there is a market potential for all product streams, including oxygen and heat and if the produced heat replaces a fossil-based heat mix.

In accordance with other studies, the fossil-based carbon intensity of the electricity mix used, especially in the case of the hydrogen production via electrolysis and the possibility to offset the co-products obtained can have a strong influence on the results. In the case of the bio-methane

reforming systems, the upstream impacts during the production of biogas used in the process would determine the overall environmental performance of hydrogen.

Methodological variations as a result of the LCA framework used and corresponding underlying assumptions is shown to affect the results obtained. Different frameworks, however, can be applied to different contexts (internal environmental work or for policy making) thus understanding the differences and interpreting the results accordingly is of vital importance.

Broadening the scope of the study by including the use phase of hydrogen in transport applications or by including additional environmental impact categories shall be a next step towards a holistic life cycle assessment. Comparisons to the fossil fuel alternatives could also highlight the full potential of hydrogen supply systems.

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## APPENDIX A – DETAILED INFORMATION ON ASSUMPTIONS FOR TECHNO-ECONOMIC MODEL

#### Table 20. Purchase prices used in the techno-economic model.

Variable	Value	Comments	Reference
Electricity alt 1	1.00 SEK/kWh	With energy taxes. Used for pressure increase and refuelling stations.	
Electricity alt 2	0.65 SEK/kWh	Electricity price (1.00 SEK) minus energy tax (0.35 SEK). Used for production.	
Bio-methane alt 1	0.70 SEK/kWh	Purchased at biogas production plant	(Börjesson, o.a., 2016)
Bio-methane alt 2	0.90 SEK/kWh	Purchased at refuelling station	(Börjesson, o.a., 2016)
Water	16 SEK/m <sup>3</sup>		Price at water utility
Nitrogen	100 SEK/Nm <sup>3</sup>	Assumption	

#### Table 21. Overall project costs used in the techno-economic model.

Variable	Value	Comments
Service & maintenance	2.5 %	Percent of investment costs
Indirect costs	10 %	Percent of investment costs
Unforeseen costs	10 %	Percent of investment costs
Labour costs	400 000 SEK/year	

#### Table 22. Distribution costs used in the techno-economic model.

Variable	Value	Comments	Reference
Loading & unloading $H_2$	0.5 h	Time for loading and unloading of trailers	(Gustafsson, Cruz, Svensson, & Karlsson, 2020)
Loading & unloading H <sub>2</sub>	650 SEK/h	Hourly costs related to loading and unloading (incl. driver + truck)	(Gustafsson, Cruz, Svensson, & Karlsson, 2020)
Specific transport cost	18.0 SEK/km	Includes the costs for fuel, driver, truck and other related costs.	(Gustafsson, Cruz, Svensson, & Karlsson, 2020)

#### Table 23. Hydrogen compression values used in the techno-economic model.

Variable	Value	Comments	Reference
Low-pressure compression $H_2$	1.20 kWh/kg	Calculation based on HDRSAM	
H <sub>2</sub> compression gas container	1.33 kWh/kg	HDRSAM	

Variable	Value	Comments	Reference
Water consumption electrolyser	0.0110 m <sup>3</sup> /kg H2		(Saulnier, Minnich, & Sturgess, 2020)
Efficiency electrolyser	62 %	Including electrolyser cell (efficiency 68%) as well as auxiliaries but NOT cooling system	NEL Hydrogen via Proost (State-of-the art CAPEX data for water electrolysers, and their impact on renewable hydrogen price settings, 2019)
Cooling requirements electrolyser	8.54 kWh/kg	Calculated	
Electricity consumption cooling system	0.00 MJel/MJcooling	Negligible	Own estimation
Surplus heat electrolyser	8.54 kWh/kg	Derived from own calculations	
Heat to district heating network	0.16 SEK/kWh	Own estimate based on ENPAC (Chalmers) and numbers from Stockholm Exergi	

Fable 24. Electrolyse	· parameters assumed	l in the techno	-economic model.
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#### Table 25. SMR values used in the techno-economic model.

Variable	Value	Comments	Reference
Water consumption SMR	0.0065 m <sup>3</sup> /kg H2	We assume that it is recirculated	(Saulnier, Minnich, & Sturgess, 2020)& (Metacon, 2021)
Efficiency reformer	75 %	Calculated	(Metacon, 2021)
Low pressure increase biogas	0.0997 kWh/Nm3	Using amine scrubber as starting point (1 bar out)	(Börjesson, o.a., 2016)
Electricity consumption reformer	0.35 kWh/Nm3	35 kW for largest	(Metacon, 2021)

#### Table 26. Refuelling station values used in the techno-economic model.

Variable	Value	Comments	Reference
Electricity consumption refuelling station off grid	1.45 kWh/kg	HDRSAM	
Electricity consumption refuelling station grid-connected	1.55 kWh/kg	HDRSAM	

#### Table 27. Production values used in the techno-economic model.

Variable	kg/year	GWh/year
Central production	1 502 783	50
Decentralised production (small)	150 278	5
Decentralised production (large)	300 557	10

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