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Deliverable 4.2: Business case and economic modelling for Green Hydrogen Production

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REPORT

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HyTrEc 2 WP4 Rapport

RISE Research Institutes of Sweden AB
Electrification and Reliability - Energy Conversion

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Work Package 4: Low Carbon Hydrogen Production, Storage and Distribution

Business Case and Economic Modelling for Green Hydrogen Production

Contents

Executive summary

This report investigates how the cost-efficiency of the production and distribution of green hydrogen and the operation of hydrogen refuelling stations can be improved. Within the report optimised strategies for the production and distribution of green hydrogen have been developed and alternative revenue sources for hydrogen refuelling stations are investigated.

The report includes two sections describing the theory behind how production and distribution of hydrogen can be optimised. These sections are then concluded with four exhibits that explore different aspects of hydrogen production, distribution and refuelling stations. The four exhibits are:

- **Exhibit A: Localised vs. Centralised production of Hydrogen**

  In exhibit A the advantages and disadvantages of producing hydrogen locally versus distributed production are compared. A case is constructed where a network of hydrogen refuelling stations have the option to either produce hydrogen locally at each station, or the hydrogen is produced on large-scale elsewhere and then distributed to the stations. Costs and other properties are compared.

  Result: Centralised production with distribution requires a very large scale of operations to yield comparable costs to localised.

- **Exhibit B: Large-Scale Hydrogen Production with Off-shore Wind**

  Exhibit B investigates how green hydrogen can be produced on a large-scale from off-shore wind by adapting a methodology from previous work [1]. The exhibit explores issues such as as what price of hydrogen does it become more cost-efficient for the wind farm to produce hydrogen rather than selling electricity to the grid.

  Result: Production costs of 3 €/kg H2 could be possible.

- **Exhibit C: HRS with Green Hydrogen Production and Additional Revenues**

  In exhibit C a case is constructed for a hydrogen refuelling station with its own electrolysis and access to wind power. It then investigates how additional revenue from the by-products, oxygen and waste heat, may improve the overall cost-efficiency of the HRS and how this compares to other variables.

  Result: Oxygen and waste heat capture do not have a significant positive impact on hydrogen production economics.

- **Exhibit D: Hydrogen Production from Variable Renewable Electricity Only**

  Exhibit D investigates how three sources of variable renewable electricity (Swedish solar power, Spanish solar power and wind power) can be used cost-optimally to produce green hydrogen off-grid. A simulation model and method is created and used to design an optimal combination of power production capacity, electrolysis capacity and hydrogen storage suited for the given source of variable renewable electricity.

  Result: Wind power has the lowest production cost by far.

Finally the report concludes with a section about lessons learned from previous projects in hydrogen production and refuelling stations undertaken by the HyTrEc2 partners. These lessons learned illustrate many of the differences between theoretical and practical usage of hydrogen.

Main conclusions

The most important conclusions found regarding the production, distribution, additional sources of revenue and Optimal vs. Real costs are the following:

Production - In the case of production of hydrogen, it is generally better paying a higher price for the electricity and having as many annual operational hours as possible than to stop production during peak electricity prices. Downtime on the electrolyser leads to high costs and requires expensive hydrogen storage in order to supply a constant demand of hydrogen. This contradicts the notion that electrolysers can be used to efficiently utilise the intermittent variations in the price of electricity.

It is also shown that it is possible to produce hydrogen cost-efficiently with a very high proportion of the electricity generated directly from renewable sources with only some support from the grid. However, to produce hydrogen based on 100 % supply of variable renewable electricity will cause a sharp increase in costs and will require storage to compensate for the variations in electricity supply.

Distribution - As for the distribution of hydrogen, the distance over which the hydrogen is transported plays an important role but not as much as the quantity of distributed hydrogen. It was found that over very short distances, pipelines with gaseous hydrogen are the most optimal solution (in terms of cost). Truck trailers with gaseous hydrogen become the best option for short to medium distances and for longer distances, truck trailers with liquid hydrogen are preferable.

In many cases, the distribution of hydrogen may cost as much or even more than the cost of production of hydrogen. Cost-efficient distribution is only achieved when large volumes of hydrogen are being transported daily. It may often be more cost-effective to have the electrolyser and hydrogen production take place directly at the refuelling station rather than distributing the hydrogen to the station from a different location.

Additional Sources of Revenue - While it is theoretically possible for hydrogen refuelling stations to increase the profitability of their operations through additional revenue sources from selling the oxygen gas or waste heat by-products from the electrolyser, it is rarely practical to do so. Even in a best-case scenario where most of the produced oxygen and waste heat can be sold at a high price, the overall economic impact is low compared to other options.

Optimal vs. Real Costs - It was found that under current modelling circumstances, an optimal production cost for green hydrogen is approximately 3 €/kg H2. The cost to distribute hydrogen could, under optimal circumstances, be range between 0.50 €/kg H2 and 1.50 €/kg H2, depending on the distribution distance. Hydrogen refuelling. Without subsidies, hydrogen refueling stations could therefore sell their hydrogen for a price as low as 5 €/kg H2.

These are however, optimal costs and they are (to date) only achievable in theory. The lessons learned from the real experiences of the HyTrEc2 partners show that the real costs are currently much higher, with refuelling stations selling their hydrogen at 10 €/kg H2 or more. The key difference between theory and practice is the degree of utilisation, which theory shows is the most important factor for achieving good cost-efficiency. As the equipment used for production, distribution and refuelling of hydrogen is still very capital intensive, it is essential that the assets are utilised as much as possible.

Whilst this report has investigated methods for how cost-efficiency can be increased through new operational strategies for the production of hydrogen and utilization of additional revenue sources, it has also been shown that these play a far smaller impact compared to simply increasing the utilisation of the equipment. Increasing the uptake of hydrogen, and raising demand so that it matches the supply available, is the most important factor.

Frequently Used Abbreviations

NSR – North Sea Region

FCEV – Fuel Cell Electric Vehicle

HyTrEc2 – Hydrogen Transport Economy for the North Sea Region 2

HRS – Hydrogen Refuelling Station

LCOH – Levelized Cost of Hydrogen

Introduction

Introduction to HyTrEc2

The HyTrEc2 (Hydrogen Transport Economy for the North Sea Region) project is an extension which brings together organisations with an interest or experience in hydrogen. The HyTrEc2 consortium collaborates on the development of strategy and initiatives across the North Sea Region (NSR) and will to support further deployment of fuel cell electric vehicles (FCEVs) in the NSR. The project forms part of the Interreg VB North Sea Region Programme and the European Regional Development Fund.

With 94 % of today's transport based on oil , green transport solutions such as hydrogen is expected to play a key role in achieving EU energy and climate change targets. Hydrogen Fuel Cell Electric Vehicles (FCEVs) are key as they have a larger driving range than electric battery vehicles and this extended range is essential in the North Sea which consists of large number of small- and medium-sized cities with a large suburban and rural hinterland. Currently, the market is under-developed attributed to the high cost of FCEVs, particularly for large fleet operators of vans. There is an urgent need to make green hydrogen cheaper through more cost-effective hydrogen production, storage and distribution

The key aim is to create conditions so that a FCEV market can develop, and promote the NSR as a Centre for Excellence for fuel cells and range extenders. The project will contribute to reducing the cost of hydrogen vehicles and reducing CO2 emissions through:

- Improving the operational efficiency of a wide range of vehicles such as vans, large trucks and refuse collection vehicles.
- Improving the supply chain and training so that the NSR becomes a Centre of Excellence for hydrogen transport and a competitive environment is formed
- Developing innovative methods for the production, storage and distribution of green hydrogen.
- Ensuring that the NSR becomes the dominant region in the EU in terms of hydrogen transport. The project will complement national programmes and facilitate joint NSR approaches and common standards.

To find out more about HyTrEc2:

- https://northsearegion.eu/hytrec2

Introduction to RISE

RISE Research Institutes of Sweden is Sweden's research institute and innovation partner. Through international collaboration with industry, academia and the public sector, RISE ensures business competitiveness and contributes to a sustainable society. RISE offers collaboration, research and advice for organizations looking to learn more about hydrogen.

To find out more about RISE and hydrogen:

- https://www.ri.se/en/about-rise/about-rise
- https://www.ri.se/en/hydrogen

Cost efficient production & distribution of green hydrogen

Green hydrogen is hydrogen produced by electrolysis powered by renewable energy. Compared to its non-renewable cousins, blue and grey hydrogen (hydrogen produced from natural gas), it is more expensive to produce; usually costing green hydrogen, typically by 2 – 3 times more [2].

In this chapter, we aim to gain understanding of the causes for the production and handling of green hydrogen to be as expensive as it is and how the cost may be reduced.

In the final section of the chapter two small exhibits illustrate the economics of localised and centralised production of green hydrogen.

Production

Green hydrogen is produced through the processes of electrolysis of water. Water molecules are split into hydrogen and oxygen gas molecules with the help of electricity. The great advantage of electrolysis is that when clean electricity is used, the process is emission-free, thereby producing zero-emission fuel (green hydrogen). This is why hydrogen has often been cited as the “fuel of the future”.

Currently, there are three main technologies for the electrolysis of water: Alkaline electrolyser (AEL), Proton Exchange Membrane (PEM) and Solid Oxide Electrolyser Cell (SOEC). Of these, AEL is the most common although PEM is quickly gaining popularity, whereas SOEC is still considered as somewhat novel.

$$2H_20 + electricity \rightarrow 2H_2 + O_2$$

Equation 1: Electrolysis of water

The cost of electrolysis

Compared to the current most common way of producing hydrogen (Steam Methane Reforming), water electrolysis is more expensive. The cost of producing hydrogen through electrolysis is usually 2.50 – 5.50 €/kg while the cost for Steam Methane Reforming is 1.50 – 2 €/kg (depending on whether carbon capture technology is used or not) [2].

There are three main factors affecting the cost of electrolysis:

- The cost of the electrolyser itself (Capital Investment)
- The cost of electricity used by the electrolyser (Electricity Cost)
- Maintenance costs and stack replacements

To measure the production cost of hydrogen, the Levelised Cost of Hydrogen (LCOH) is used. This is simply the sum of all cost of producing hydrogen divided by the total amount of hydrogen produced over the lifetime of the plant, with interests included.

Capital Investment

An electrolyser is a fairly expensive piece of equipment which requires a large investment. Commonly, an alkaline or PEM electrolyser will cost 420 – 1500 € per kilowatt [3]. While the global experience with large scale electrolysers is still limited (the world's largest PEM electrolyser is currently at 20 MW [4]), recent studies [5], [6] suggest that there are economies-of-scale benefits for larger electrolysers as illustrated in Figure 1.

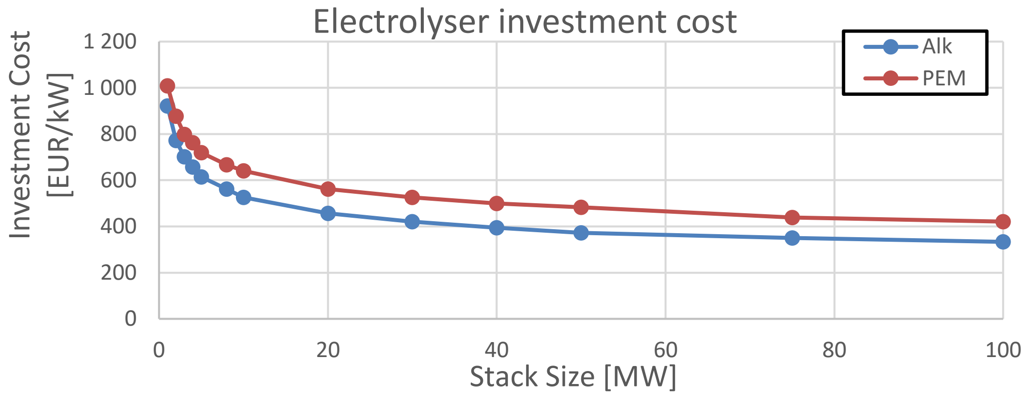

Figure 1: Electrolyser investment cost. Source: [5]

Another important aspect to consider is the efficiency of the electrolyser. Currently, the full system for an alkaline electrolyser will require about 45 - 55 kWh of electricity to produce 1 kg of hydrogen (equivalent to 33.33 kWh by the Lower Heating Value). This implies that the electrical efficiency of such an electrolyser is about 60 - 74 %. Electrolysers will deteriorate over time, losing efficiency and performance such that the stack (where the electrolysis happens within the machine) eventually has to be replaced.

Electrolysers are constantly improving both terms of cost and efficiency. Even though electrolysis of water is a fairly old and well-known technology, electrolysers have not seen much widespread commercial use. This means that there is room for improvement in terms of economies-of-scale and increased funding/interest for researching and improving electrolyser technology. In the 2019 report "The future of Hydrogen" [3], the International Energy Agency estimated that both the cost and efficiencies of all three electrolyser technologies will improve significantly in the coming years as can be seen in Figure 2.

	Alkaline electrolyser			PEM electrolyser			SOEC electrolyser		
	Today	2030	Long term	Today	2030	Long-term	Today	2030	Long term
Electrical efficiency (%, LHV)	63–70	65–71	70–80	56–60	63–68	67–74	74–81	77–84	77–90
CAPEX (USD/kW$_e$)	500 – 1400	400 – 850	200 – 700	1 100 – 1 800	650 – 1 500	200 – 900	2 800 – 5 600	800 – 2 800	500 – 1 000

Figure 2: Excerpt from [3]

Since electrolysers are expensive investments, it is essential to operate them at maximum capacity in order to generate as much value from the capital investment as possible. An electrolyser is limited by its maximum rated power and by the hours per year it is in operation. The only way to increase production is to run the electrolyser more often. A common metric used to measure how much of the capacity of an electrolyser is being utilised is the capacity factor (CF). The capacity factor is defined by the actual amount of power consumed by the electrolyser in a year divided by its maximum potential power output times 8760 h (8760 hours in a year not counting leap years).

$$CF = \frac{Consumed\ Power}{Rated\ power\ \times 8760\ h}$$

Equation 2: Capacity factor

For instance, an electrolyser that operates at full power for 8000 hours and is shut down for the remaining hours of the year has a CF of 91.3 %. The goal should be to keep the CF as high as possible as this implies efficient utilisation of the electrolyser's capacity, which leads to a lower cost of producing hydrogen. It is however, not possible to have a CF of 100 %, as the electrolyser will occasionally have to be shut down for maintenance or similar. Sometimes, the price of electricity is so high that it may not even be worth running the electrolyser.

Electricity Cost

To produce hydrogen, electricity is required and electricity costs are a significant part of the cost of producing hydrogen and usually a large influence on the price of the hydrogen sold. And is therefore an important factor. Assuming an electricity price of 50 €/MWh and an efficiency of 55 kWh/kg H2, the cost of producing hydrogen is at least 2.75 €/kg H2 due to the electricity cost alone. Complicating matters further, the spot price of grid-electricity varies over time and may sometimes be momentarily very high but also occasionally negative [7]. Electricity prices not only vary over time but also by location; some countries or regions may have significantly cheaper and less volatile electricity prices than others. Also, the cleanliness of the electricity will vary, with as some countries still relying on large amounts of fossil power to produce electricity, which in turn causes the electrolysis to have a large carbon footprint, defeating the original purpose of reducing emissions. To ensure a cost-efficient production of hydrogen, the electrolyser should operate as little as possible when the price of electricity is high and as much as possible when it is low.

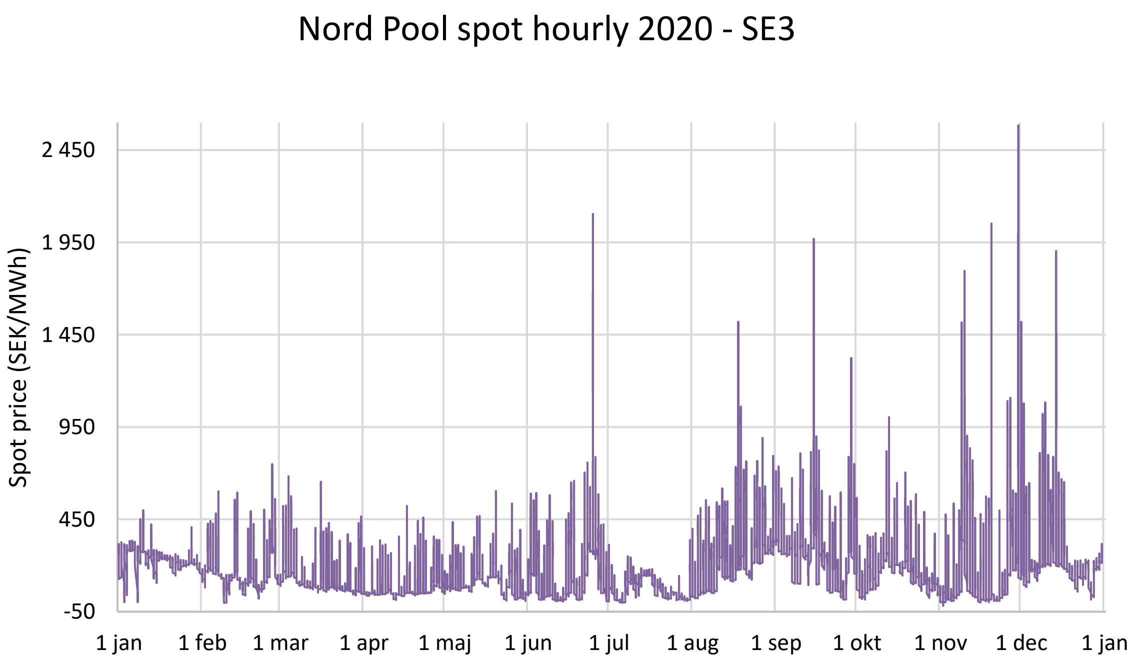

Figure 3: Example - Spotprice for electricity in Sweden - SE3.

Cost efficient operation of an electrolyser

To produce hydrogen as cost-efficiently as possible, a balance must be found between operating the electrolyser as much as possible (to keep the CF high) and avoiding operation when the price of electricity is very high. This section illustrates how a simple rule can be used to operate an electrolyser at the cheapest possible electricity price. The rule is that if the hourly spot price of the electricity is above a certain threshold, the electrolyser will be shut off. If the price, on the other hand, is lower than the threshold, the electrolyser shall operate at full power.

The challenge is to set the threshold correctly. If it is set too low, the electrolyser might operate when the electricity is expensive, whereas if it is set too high, it will not operate at optimal capacity. The optimal threshold provides a balance between low electricity prices and high operating hours.

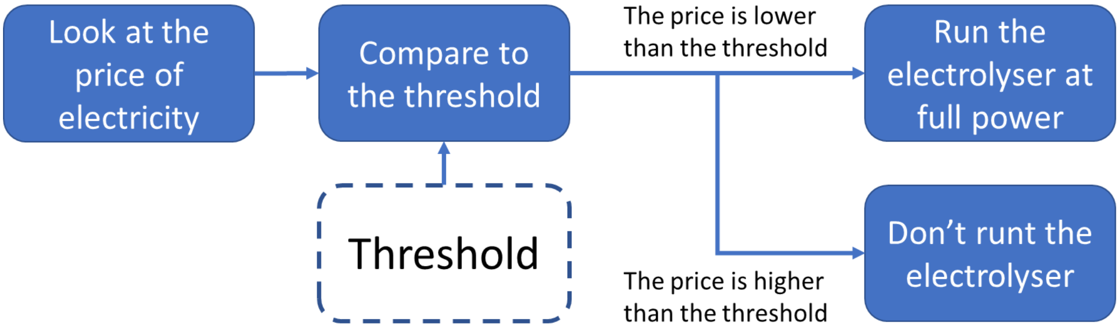

Figure 4: Flow chart for the operational algorithm of the electrolyser

Example 1 (Without hydrogen storage)

We can calculate the cost of producing hydrogen by using historical spot price data for electricity that is publicly available at Nordpoolgroup.com. For this example a 1 MW electrolyser is used with data from the year 2020 for the electricity area, SE3, in Sweden (includes Stockholm and some other major cities). In the data, there are fairly large variations in the spot prices (Figure 3). The highest recorded price is at 258.40 €/MWh, while the lowest is at -1.79 €/MWh, giving an average of 22.103€/MWh. When varying the threshold between 10 and 50 €/MWh, the following results are seen (Figure 5 & Figure 6).

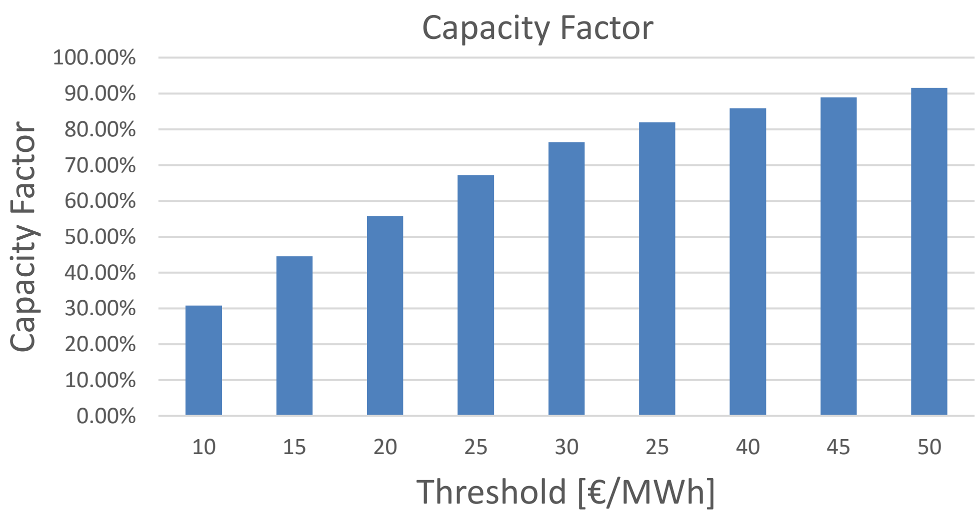

Figure 5: Capacity Factor as a function of the threshold

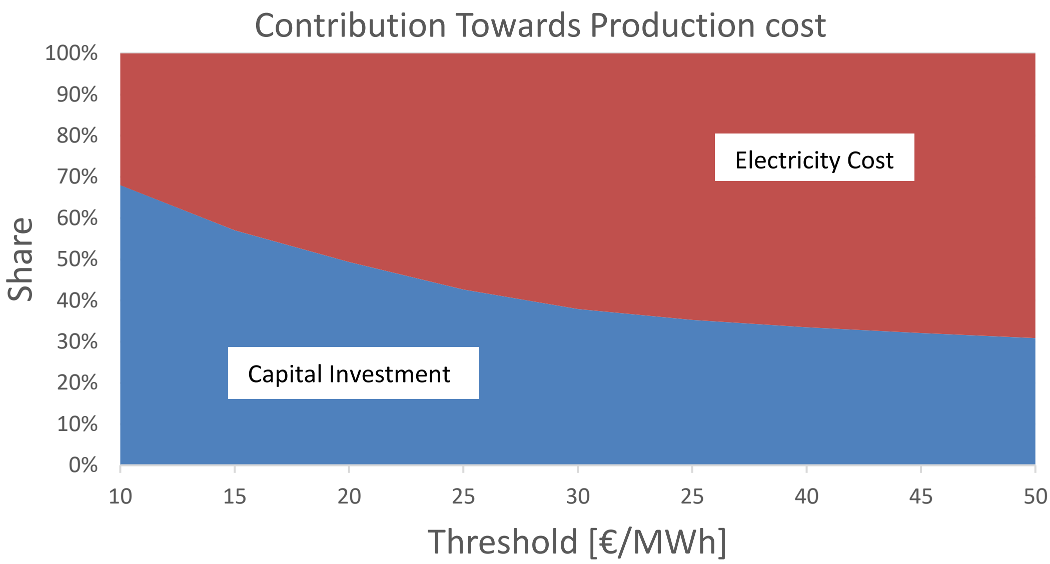

Figure 6: Contribution to production cost as a function of the threshold

The most cost-efficient means of hydrogen production is achieved when the threshold is set to about 30 €/MWh. At this point the LCOH becomes 2.54 €/kg H2 and the CF is 76.4 %. Capital Investment comprises 38 % of the cost and electricity accounts for the remaining 62 %. If the threshold is increased over this level, the LCOH increases only slightly. Even when the threshold set at 260 €/MWh (such that the CF is 100 %), the LCOH increases only to 2.77 €/kg H2. However, when the threshold is reduced to 10 €/MWh, the LCOH soars to 3.51 €/kg H2 . The conclusion drawn from this example is that a high CF is required for cost-efficient hydrogen production. The threshold should be set at a relatively high price (about 150 % of the average electricity price in this case) as a higher threshold price does not lead to a significant increase in the overall cost much extra if the threshold was set even higher.

However, this solution may not be an accurate representation of how an electrolyser can be operated in practice. In reality, based on the current method, the electrolyser will not produce hydrogen when the spot price is high, which usually occurs at night and in the winter months. This may lead to a shortage of hydrogen during those times. For instance, if this electrolyser is to supply a hydrogen refuelling station with hydrogen, such a shortage would be unacceptable, since as there would be no fuel for the vehicles. Conversely the opposite may happen too; the electrolyser may produce hydrogen when nonespot price is low and when demand is also low, leading to overproduction

Example 2 (With hydrogen storage)

The solution to this problem is to use hydrogen storage, which comes at an additional cost. The storage has to be large enough to manage the mismatch between production and demand of hydrogen, and the. The larger the variations in production and demand, the larger storage is required. In this example, storage requirements are included in the calculation. It is assumed that an even demand of hydrogen is present at all times. When the threshold is low, gaps in the production of hydrogen become more frequent and greater, thus, thereby requiring a larger storage. At high threshold, the production is more constant, which reduces the need for storage. The cost for storage is included in the production cost of the hydrogen. The capital investment for the storage is assumed to cost 475 €/kg H2 [8]

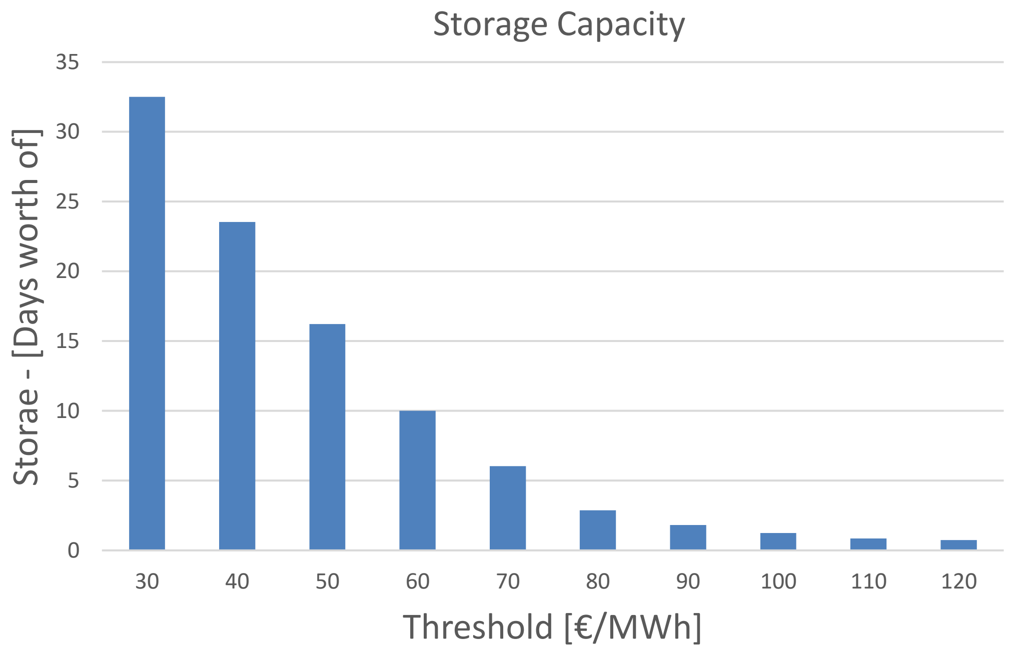

Figure 7: Storage requirements (Measured as days worth of hydrogen consumption)

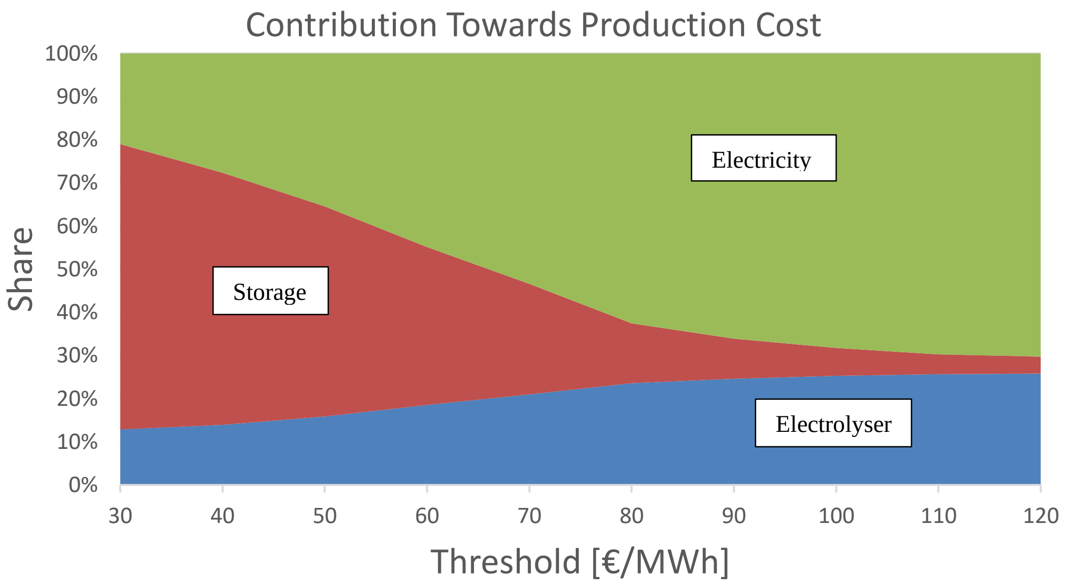

Figure 8: Contribution to cost divided between Storage, Electrolyser and Electricity

When storage cost is added to the picture, the LCOH is increased significantly. For a threshold of 30 €/MWh a storage of 32 days-worth of hydrogen consumption is required and the LCOH is 7.50 €/kg H2. The storage requirement decreases rapidly as the threshold increases. At a threshold of 100 €/MWh, only a little storage is required and the LCOH drops to comparable levels as previously. The lowest LCOH is reached at a threshold of 250 €/MWh, just one hour shy of 100 % CF. In conclusion, when storage is taken into account, the arguments for a high CF are amplified. To keep the production cost low, the CF should be as high as possible.

Conclusion & Key findings

Electrolysis is often mentioned as a means to use excess surplus renewable electricity or to take advantage of the variations in electricity pricing. This is however, an inefficient and costly way of producing hydrogen, compared to other production alternatives. With current variations in the way pricing at the moment, it is more cost-efficient to operate at high electricity prices rather than to invest in extra storage. In addition, the high investment cost of the electrolyser itself means that its is costly not to operate the electrolyser at all times. In the future, however, this may change. Flexible and varied hydrogen production is only likely to become viable if, the price of electrolysers and storage decreases, while cost need to decrease as electricity prices become even more volatile. This is likely to occur as the share of intermittent electricity production from solar and wind increases, while electrolysis and other hydrogen technologies become more mature in the market.

There is also the possibility to reduce the cost of producing hydrogen by utilizing locally-produced electricity, which does not require transmission fee nor energy tax. In previous examples, the transmission fee has been assumed to be 15 €/MWh in addition to the spot-price. While it is impossible for an electrolyser to have a CF as high as 100 % based on variable locally-produced power alone, it should be possible to substitute some of the electrolysers' power demand with locally-produced power, by situating it close to a solar park or wind farm.

The key findings from this analysis are summarised in the flow chart below. The most important takeaway is that a stable production rate close to the electrolyser's maximum capacity will minimize overall cost by reducing storage requirements while producing as much hydrogen as possible, in spite of the occasionally very high price electricity.

In the investigations conducted throughout the chapter, it has been shown that a production cost of green hydrogen of 2.50 – 3 €/kg H2 is attainable under favorable conditions.

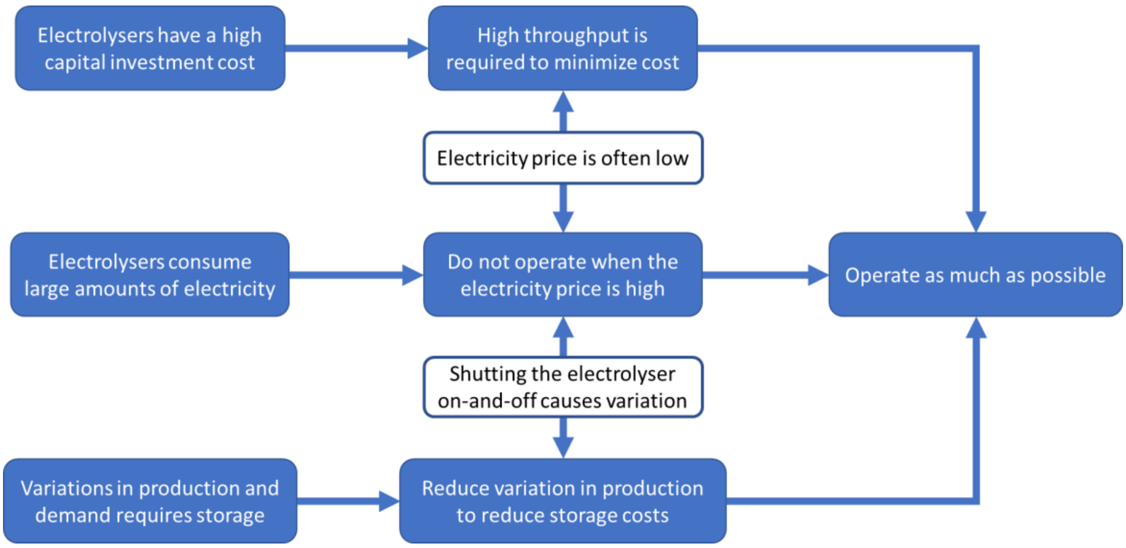

Figure 9: Flow chart - How should the electrolyser be operated? (the chart seems a bit confusing with the arrows: not quite sure how it explains the nature of relationship between the bubble in blue and white bubble

Distribution

Electrolysis enables the production of hydrogen at any location, where access to water and electricity can be ensured. However, the most optimal locations for green hydrogen production are those where the electricity is guaranteed to be renewable and reasonably priced.

In this report, we focus on land-routes for distributing hydrogen. Hydrogen can be distributed from where it is produced to where it is to be consumed via three main routes:

- In gaseous form on truck-trailers (GH2-trailer)
- In liquid form on truck-trailers (LH2-trailer)
- In gaseous form through pipelines (Pipeline)

GH2-trailer

Truck-trailers can be equipped with pressure cylinders and act as mobile storage of hydrogen. This solution is convenient because it can also serve as a stationary storage at the fuel station. The capacity of GH2-trailers is limited by regulations. In Europe, the regulations allow for relatively high capacities and pressures. The company "Hexagon Purus" advertises that its GH2-trailer "X-Store 40 ft" has a capacity of 1 115 kg H2 at pressures of up to 500 bar which is still under consideration for approval by the relevant ISO, EN, CSC and ADR regulations [9].

To fill a GH2-trailer with hydrogen, compression is required. Electrolysers typically produce hydrogen at a pressure of 1 – 35 bar whilst the GH2-trailers require 300 – 500 bar of pressure. To calculate the cost of distribution of hydrogen via GH2-trailer, we have to include the cost of compression.

Figure 10: Hexagon Purus X-Store. Picture from: https://cdn.hexagongroup.com/uploads/2020/03/Data-sheet_Hexagon_Purus-X-STORE_Hydrogen_500bar.pdf

LH2-trailer

Hydrogen can also be stored and distributed in liquid form. In liquid form, hydrogen has a much higher gravimetric density than in gaseous form. This makes it possible to load much more hydrogen into one trailer (approx. 4 000 kg H2). Storage alone for liquid H2 is also more cost-efficient. Based on our calculations, the cost of distribution by LH2-trailer is approximately 20 % less than GH2-trailer while containing 260 % more H2, making it 340% more cost-efficient.

There are, however, some disadvantages with liquid hydrogen. Hydrogen cannot exist in liquid form unless its temperature is below 33 K (-240.15 °C) or less [10], which means it will rapidly evaporate into gaseous form if stored at room temperature. To prevent this, storage tanks for liquid hydrogen are thoroughly isolated to keep the warmth out. They are sometimes manufactured in spherical shapes to minimize the surface area in relation to its volume (a great example can be seen the LH2-tank used by Nasa to store rocket fuel). Regardless of the measures, some evaporation will always occur and gas will accumulate within inside the LH2-tank. The LH2-tanks are not built to withstand large pressures, so to prevent too much gas from accumulating and building up pressure, the gas is vented. This is also known as "boil-off". Due to boil-offs, some of the hydrogen is always will be lost when dealing with LH2. This is however, usually not a significant problem as it takes some time for the heat to build up. Unless the tank is left unused for several days, boil-off losses will be minor. Some boil-offs will also occur when pouring/filling the LH2. In total, boil-off losses may not be more than a few percent or even less [11]. Liquid hydrogen is produced from gaseous hydrogen through a process known as liquefaction. Liquefaction is quite an expensive and energy-intensive process. Approximately 10 – 13 kWh of electricity is required to liquify 1 kg of H2 [12] and liquefaction plants have to be enormous in capacity so as to be efficient. Liquefaction plants commonly process several tons of hydrogen each day [11]. As such, unless the hydrogen is intended to be used in liquid form in its end use, liquefaction becomes an additional cost for distribution. (Liquefaction is included as a cost in our calculations).

Figure 11: LH2-tank at Kennedy Space Center. Picture from: https://www.nasa.gov/sites/default/files/thumbnails/image/0-43485369735_45b9ffa8b6_1.jpg

Pipelines

Hydrogen can be transported through pipes. Large-scale hydrogen pipelines are able to transport large quantities of hydrogen at pressures of around 20 – 100 Bar. The disadvantage of pipelines compared to truck transports is the lack of flexibility as the pipeline can only transport from one location to another (and those in between) while a truck may transport anywhere where there are appropriate roads. The upfront investment cost for a pipeline may also be quite high. Due to above-mentioned reasons, pipelines will only be a suitable option for distribution in certain cases, such as when a large quantity of hydrogen has the be transported over a shorter fixed distance. An example of such a case could be an electrolyser placed at an off-shore wind park where the hydrogen is then transported ashore.

While dedicated hydrogen pipelines on the scale of those for natural gas are still uncommon, there already exists 1600 miles (2575 km) of hydrogen pipeline in the United States [13]. It is also possible to retrofit existing pipelines for natural gas to accommodate hydrogen instead.

Distribution costs

The cost of distributing hydrogen will highly depend on the volume and distances over which the hydrogen is transported, as well as the mode of transportation (GH2-trailer, LH2-trailer or pipeline) will also have a large impact.

In the 2007 paper on "Determining the lowest-cost Hydrogen Delivery Mode" [14], the authors calculated the cost of distributing hydrogen via trailer or pipeline. The paper is now somewhat outdated due to its age and some of the assumptions are no longer accurate (especially for European conditions). The methodology however, still holds. To calculate the distribution costs we have used the same methodology but revised it with more recent and accurate assumptions. For the trailer-transport, a point-to-point model is used which means that the trucks drive back and forth between a pick-up-point and delivery-point. This provides a simple "worst-case" cost for the distribution cost.

Figure 12 below illustrates the cost of distribution and the cheapest distribution-mode for different capacities and distances of distribution. The color-scale illustrates which mode is the cheapest: for. For short distances (< 25 km), pipeline is generally the cheapest option;, whereas for medium distances (25 – 600 km), GH2-trailer is the cheapest; and, for long distances (> 600 km) LH2-trailer is the cheapest. The solid and dashed lines in black indicate how the distribution cost varies with capacity and distance. Overall, the cost of distribution ranges from 0.50 €/kg H2 to 5 €/kg H2. Distribution generally becomes cheaper at larger capacities and shorter distances. This means that it is not worth transporting hydrogen too far as it would be cheaper to set up a new hydrogen production site at a far-away destination point than to transport hydrogen over long distances. It is also not worth it distributing small quantities of hydrogen either. The as illustrated in Figure 12, where the scale starts from 500 kg H2/day, which equates to 100 re-fuellings of regular hydrogen cars (such as the Mirai) every day.

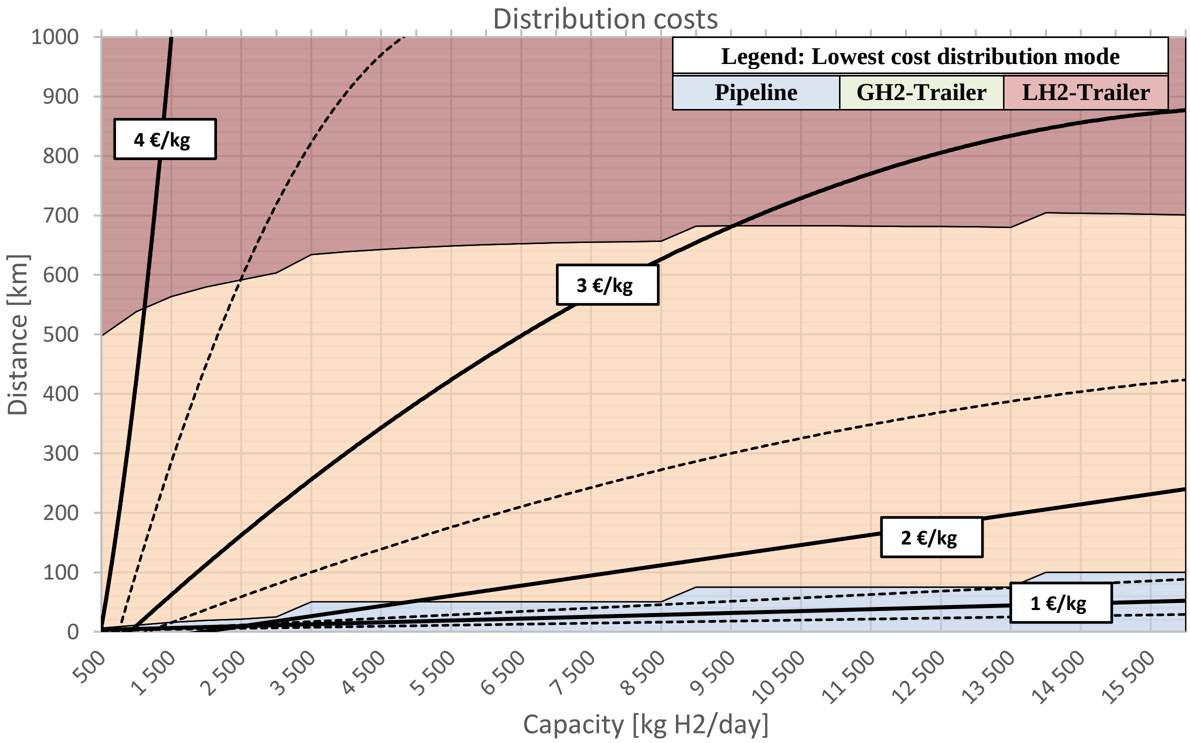

Figure 12: Distribution costs and lowest-cost distribution mode

Cost breakdown and analysis

The cost situation for the pipeline is quite uncertain. Previous works such as "European Hydrogen Backbone" [15] only cite prices for very large pipelines (48"). Based on previous experience, an investment cost of 1 000 000 €/$km_{pipeline}$ has been assumed. As the cost of the pipeline scales quickly with distance, the longer the pipeline the more expensive it becomes. As such, it is not favorable to build pipelines over longer distances unless it is distributing a significant volume.

For the trailer options, part of the cost comes from the distribution centre (where the hydrogen is either compressed or liquified and then deposited in liquefied form before being loaded into the trailer), while the other part comes from owning and driving the truck & trailer. Liquefaction can be 20 – 120 % more expensive than compression (depending on the capacity) and constitutes for the most significant part of the distribution cost for the LH2-trailer option. Not only is liquefaction expensive due to the large capital investment required for liquefaction plants, the cost of electricity is also quite substantial. We have assumed in this case an energy-efficiency of 13 kWh/kg H2 for liquifying the hydrogen. This is a conservative estimate as the energy efficiency may also be as low as 10 kWh/kg H2 or even lower in the future due to new emerging technologies [12].

In this example, liquefaction is considered an additional cost. However, depending on how the hydrogen is to be used, there may be advantages (or even a requirement) to have the hydrogen in liquid form. For instance, Daimler's new liquid hydrogen trucks will require the hydrogen to be delivered in liquid form at the fuel station, making LH2-trailer delivery the only option. It is also possible that the cost of handling the hydrogen at the hydrogen refuelling station may be lower with liquid hydrogen. For the GH2-trailer option, and for very short distances (< 25 km), about 70 – 90 % of the distribution cost comes from the distribution centre, whereas at very long distances (1000 km), it's about 30 – 50 %. For the LH2-trailer option, on the other hand, the distribution centre plays a much larger part; the LH2-trailer option has an increased cost from the beginning due to the liquefaction but the overall cost does not increase significantly with distance, making it the cheapest option for very long distances (> 600 km).

For the GH2-trailer option, the cost of distributing hydrogen scales up with distance much faster than for the LH2-trailer option. This is due to the much smaller capacity of the trailer as more trailers and more runs are required to deliver the same amount of hydrogen. For longer distances and at high capacities, the trucks will not only have to drive more kilometers, they will have to spend so much time driving that there aren't enough hours in a year for a single truck & trailer to deliver all of the hydrogen. As a result, as capacity and distance increases, more trucks & trailers are required. We have assumed here that the trucks are available 7000 h of the year. A large proportion of the cost of transporting the hydrogen is attributed to the cost of fuel for the truck and the driver's salary (and associated costs such as insurance). In the model, it is assumed that the trucks use diesel and consume 3.4 l Diesel/100 km at a diesel price of 1.50 €/l. The driver of the truck is assumed as an hourly cost of 30 €/h.

Table 1: Truck & Trailers required to deliver 8000 kg H2/day at different distances

Distance	GH2-trailer	LH2-trailer
25 km	1	1
250 km	4	1
500 km	7	2

In the future, some of the larger costs such as for the distribution centre (both GH2 and LH2) holds the potential for further cost reductions as advances in hydrogen compression and liquefaction are made. Other costs, such as the driver, have less potential for future cost reductions. It would also be reasonable to assume that the transports are made via hydrogen-trucks instead of diesel trucks, which (hopefully) should come at no additional cost in the long term. For the GH2-trailer, the cost is quite evenly spread across the different contributors, which means that no single breakthrough in a field will largely impact the cost of distribution (unless perhaps for compression). For the LH2-trailer, however, there is large potential for impactful improvement in the liquefaction process.

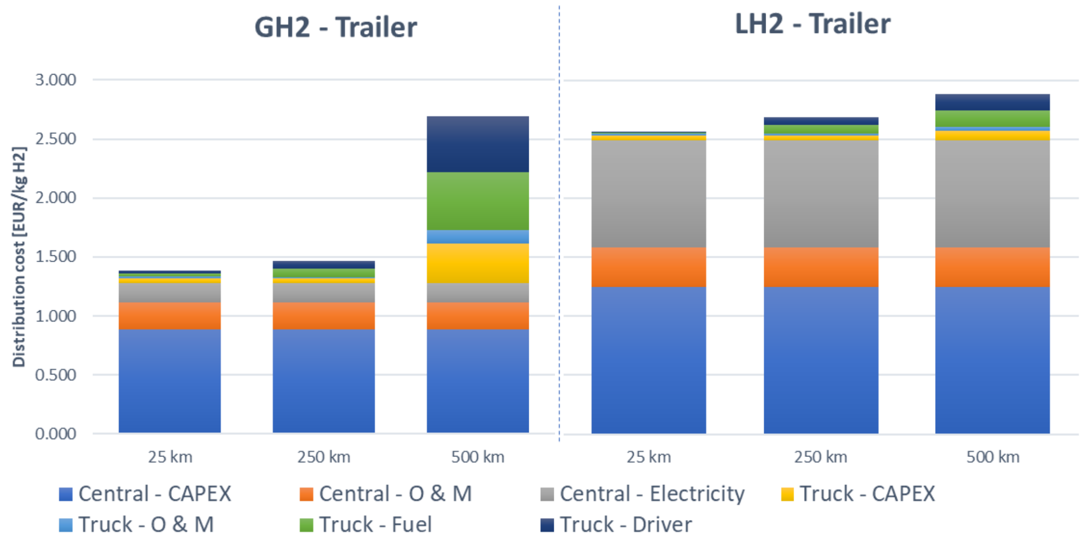

Figure 13: Cost-breakdown between GH2- and LH2-trailer (8000 kg H2/day)

Conclusion & Key-findings

There are three options for distributing hydrogen: GH2-trailer, LH2-trailer and pipeline. Which option is the most cost-efficient mode of distribution depends on the combination of volume (how much hydrogen) and the distance (how far). For all three options, distribution becomes more cost-efficient when the capacities are large and the distances short. Pipelines are the most suitable over shorter distances, approx. 25 km or less. For pipelines to be cost-efficient over longer distances, much larger pipes and capacities are required than what is shown on the scale in Figure 12. GH2-trailer is the best option for distances between 25 – 600 km, making it the most versatile option. The LH2-trailer option is not significantly affected by longer distances but has a large upfront cost due to liquefaction. This makes LH2-trailer the most cost-efficient option at long distances (> 600 km) but still quite an expensive option, usually costing 2.50 €/kg H2 or more. It also has the advantage of providing the hydrogen in liquid for which may it be advantageous for some applications. For the GH2-trailer option, which is the most versatile, the **distribution cost for realistic scenarios could be around 0.50 – 1.50 €/kg H2**.

Compared to what is commonly known cost of producing hydrogen (3 – 6 €/kg H2), distribution cost may be as expensive or even more expensive than the production process cost itself. This strengthens the case for avoiding distribution entirely by placing the electrolyser locally right where it is needed instead. However, there may still be a case for distribution if it is possible to access certain advantages at specific locations, such as cheaper and cleaner electricity or economies-of-scale type benefits. This is explored in a later section.

Additional sources of revenue for electrolysis at HRS

As introduced earlier in this report, there are opportunities for hydrogen refuelling stations and electrolysers to participate in markets other than the hydrogen market. By doing this, it is possible to generate additional revenue sources which, in turn, enables can offset the the cost of production of hydrogen. Three such revenue sources are explored: The utilization of waste heat and oxygen from electrolysers located at hydrogen refuelling stations.

Oxygen

Concentrated oxygen gas is produced as a by-product of water electrolysis (see Equation 1). For every one kilogram of hydrogen produced, 7.92 kg of oxygen is produced. In most cases, the oxygen gas is vented straight to the atmosphere and not utilised.

Uses of oxygen

Concentrated oxygen gas is a common product used for a variety of applications such as in industry, medicine, energy, waste water treatment and more.

Industry – In terms of volume. industry is the largest user of oxygen gas. Oxygen is commonly used in the manufacturing of steel, paper, glass and certain chemicals. These large-scale users of oxygen require so much oxygen that they have their own on-site oxygen production at the facility. Oxygen produced in this way generally cost 50 €/ton O2 [16].

Medicine – Oxygen is used for many medical treatments. Hospitals, for instance, use oxygen in intensive care. Many hospitals have their own supply system of oxygen at the hospital. For instance, they may have a large storage vessel for liquid oxygen which then distributed through the hospital via piping. Oxygen is also used for at-home treatments. Patients may have cylinders of compressed oxygen gas delivered to their home or they may use oxygen concentrators which are small apparatuses which concentrate oxygen from the atmospheric air.

Energy – In the energy sector, oxygen has the potential to be used for gasification or oxygen enriched combustion. Fuels which are burned in an oxygen-rich environment produce flue gases with a high concentration of carbon dioxide. This means that carbon capture and storage much easier to apply to the flue gases. This is not a process that is common today, but has the potential for growth in the future [17].

Waste water treatment – Oxygen can be used to treat waste water in various ways. The biological processes which are commonplace at treatment plants require that oxygen is added. This can be achieved by blowing regular air into the processes tank or by using concentrated oxygen. Ozone manufactured from oxygen gas can also be used at treatment plants for tertiary treatment (the special removal of certain particles which may otherwise difficult to biodegrade).

Miscellaneous – There are also many rather niche or small scale uses of oxygen gas. Examples of such uses are for example in workshops where oxygen is used for oxy-fuel welding and cutting. Other examples are fish farms and breweries.

Business opportunities for small-scale electrolysis

Even though there are many uses for oxygen, the actual beneficial business opportunities for oxygen from electrolysis are rare. This is because of a number of reasons. A large part of the cost of oxygen for the end users comes not from the manufacturing of the gas but from the handling and transport. This is why many distributors of oxygen and other gases distribute and store their product in liquid form which is more efficient. Since oxygen is a byproduct of water electrolysis, the cost of production of oxygen is considered “free” as it is a by-product. However, this may not add up to much benefit given that the main cost of oxygen is attributed to logistics and not production. The cost of logistics are dependent on scale where larger scale leads to lower cost and more efficiency. Very large electrolysers (multiple megawatts) may reach the scale where distribution of the oxygen may be worth considering but this is unlikely for small electrolysers such as those at refuelling stations it will not.

This means that for HRS and other smaller electrolysers, the only real possibility to utilise the oxygen is if it can be sold and used at the same (or very close to) geographical location as it is produced. For instance an, a HRS placed in very close proximity to a waste water treatment plant could have a pipeline that diverts the oxygen from the electrolyser to the treatment plant. Such opportunities are not, however, likely to be common. The location of the HRS should always be placed where the hydrogen is needed (as this is after all id the main business) and not the oxygen.

In those cases where the oxygen can be sold, it can be expected that it can be sold for around 50 EUR/ton O2 as this is the cost of manufacturing oxygen in industrial environments [16]. In a best-case scenario where the oxygen is sold without any cost, this yields about 0.40 € of profit per kilogram of hydrogen produced. This means that in an absolute best-case scenario where hydrogen is produced for 2.50 - 3 €/kg H2 the cost of the hydrogen can be reduced to 2.10 – 2.60 €/kg H2 with the sale of oxygen.

Heat

The two most common electrolysis technologies, Alkaline and PEM, produce excess low-grade heat at temperatures of 50 – 80 °C [18]. This heat is cooled off but could in theory be harvested and utilised. Electrolysers commonly have efficiencies of around 60 - 70 % which means that up to 40 % of the input energy is wasted [3]. Not all of the wasted energy is turned into heat but it is estimated that by utilizing the waste heat, the overall energy efficiency of the process can increase to 80 - 85 % [19].

The waste heat from the electrolyser is of low grade, which means that its uses in an industrial context are limited. Low-grade heat can however still be utilised for some purposes such as heating of homes (possibly combined with a heat pump), low temperature district heating or for various other activities that require modest heat such as the drying of fruit and biomass [20]. An example where waste heat from electrolysis will be utilised for the heating of homes is found in the newly built city district of "Neue Weststadt Klimaquartier" in Esslingen, Germany, where it is planned that the heat from electrolysis process will be used for heating some buildings. It is estimated that up to 25 % of the electricity input to the electrolyser can be received as heat [19].

As low-grade heat is relatively common and easily available, its economic value is rather low. In Sweden, one of the more common ways to receive low-grade heat is through district heating. Typical costs for such low-grade heating from district heating is 50 €/MWh excluding taxes [21]. An electrolyser with an efficiency of 55 kWh/kg H2 could produce around 14 kWh of useful heat per kilogram of hydrogen if the waste heat can be utilised as it is in Esslingen. If this heat can be used to fully replace heat from district heating, it is possible to save up to 0.70 € in heating costs per kilogram of hydrogen produced. In other European countries where district heating is not as common, natural gas may be used for heating. Typical natural gas prices in Germany are around 15 €/MWh (although as of late 2021, prices soared to as high as 82 €/MWh!) [22]. This means that the value of the replaced heat becomes 0.20 € per kilogram of produced hydrogen.

Exhibit A: Localised vs. Centralised production of Hydrogen

This section will illustrate and compare localised versus centralised production of hydrogen for hydrogen refuelling stations. In this hypothetical case study, it is imagined that an European region has a long term plan to establish a region-spanning network of a total of 30 HRS and each HRS is to deliver 1 000 kg H2/day once operational. There are two options: Either each HRS can be equipped with its own local electrolyser and produce its own hydrogen or hydrogen is produced from a central production facility and then transported to the HRS via GH2-trailer. The local electrolysers would be grid-connected whilst the production hub would be placed in conjunction with renewable energy sources, ensuring cleaner and cheaper (electrolyser is placed before-the-meter so that no transmission fee is paid) electricity.

Results

Due to economies of scale, the centralised option has a lower production cost. This is however offset by the added cost of distribution. At this scale, both options result in approximately the same cost of producing and delivering hydrogen at about 3 €/kg H2. At a larger scale, the centralised option could be even cheaper. The centralised option also enjoys the benefit of having a high degree of renewable power while being able to provide hydrogen to other customers such as a local industry. The downside for the centralised option is however, a larger total investment cost (approx. 100 M€) which has to be paid upfront. For the localised option, the total investment cost for all 30 electrolysers is 70 M€, which can be split up into individual investments of 2.50 M€ for each station. However, since grid power is used for the localised option, it is not possible to ensure that the origin of the electricity comes from renewable resources

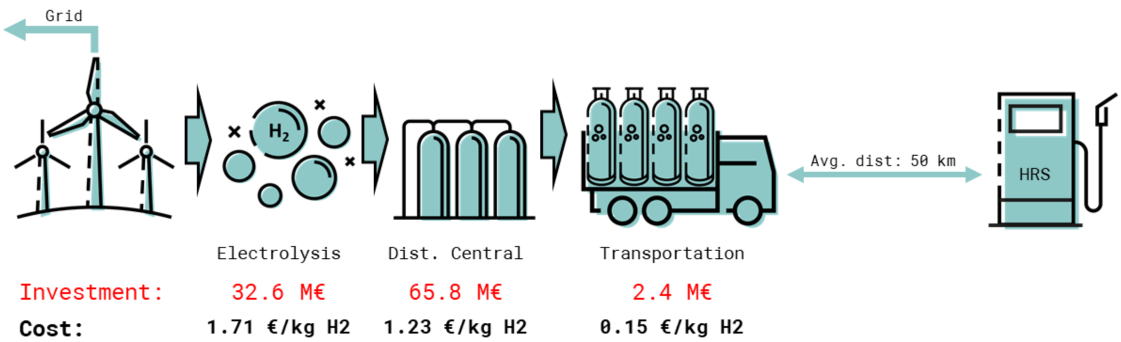

Figure 14: Centralised production of hydrogen

Table 2: Input and Results: Localised vs. Centralised production of Hydrogen (Estimated costs in 2020)

Scenario	Localised Hydrogen Production	Centralised Hydrogen Production
Refuelling stations	30 HRS with electrolysers	30 HRS with GH2-trailers
Hydrogen per station	1 000 kg H2/day	1 000 kg H2/day
Total Hydrogen demand	30 000 kg H2/day	30 000 kg H2/day
Avg. Electricity cost	37.1 EUR/MWh	22.1 EUR/MWh
Avg. Distance to station	0 km	50 km
Electrolyser(s)	30 x 2.83 MW	1 x 85 MW
Production cost	3.09 EUR/kg H2	1.71 EUR/kg H2
Distribution cost	0 EUR/kg H2	1.23 EUR/kg H2
Total cost	**3.09 EUR/kg H2**	**2.94 EUR/kg H2**

Conclusion

Between the two options there is no clear winner; both offer distinct advantages and disadvantages. With centralised production it becomes easier to benefit from economies-of-scale and reduced production costs, however it does not become viable unless a certain scale is reached. The centralised option is preferable in densely populated areas where there may be multiple HRS or other hydrogen consumers within close proximity. A centralised production facility also makes it so that cheap hydrogen becomes available to a wider audience which can further develop a hydrogen economy. Another argument for centralised production is that cheap renewable electricity is not always available everywhere in large amounts, with centralised production it becomes possible to import green energy from where renewable electricity is available to where it is not.

For early small scale demonstration projects it becomes preferable to use localised production since there is not sufficient scale to justify the additional cost of distribution. However large single-source consumers of hydrogen such as refineries could prefer localised production since the hydrogen demand is large enough to justify a larger and more cost-efficient electrolyser. For rural areas localised may be prefered since the long distances cause transportation costs to increase substanstially.

Table 3: Generic comparison: Localised vs. Centralised Hydrogen Production

Localised Hydrogen Production	Centralised Hydrogen Production
+ No distribution required + Viable at small scale + Lower upfront investment cost + Investment can be split up - Less economies of scale benefits - Grid connection required - Origin of electricity can't be controlled Suitable for: • Demonstration/Pilot projects • In rural areas with long distances • Large H2 consumers such as refineries	+ Much lower production cost + Benefits from economies-of-scale + Origin of electricity can be controlled + Can provide H2 to other industries - Requires extremely large scale - High upfront investment cost - Investment required upfront - Distribution cost Suitable for: • Densely populated areas • A wide and diverse customer base • Areas with limited access to renewable energy

Exhibit B: Large-Scale Hydrogen Production with Off-shore Wind

This section will illustrate how electrolysis can be used to improve the economics of an off-shore windfarm whilst producing 100 % green hydrogen.

Method

In this exhibit, a hypothetical off-shore windfarm sells electricity to the grid at the current spot price value. The windfarm is equipped with a Power-to-gas facility (includes electrolysis, compression and storage) such that, when the spot price is low, hydrogen is produced with the electricity instead. When the value for hydrogen energy is higher than the equivalent amount of electricity required to produce hydrogen, the electrolyser will operate. Otherwise, it is shut down.

$$When:\ Price_{electricity} < Price_{hydrogen} \cdot \eta_{PtG} \rightarrow Produce\ Hydrogen$$

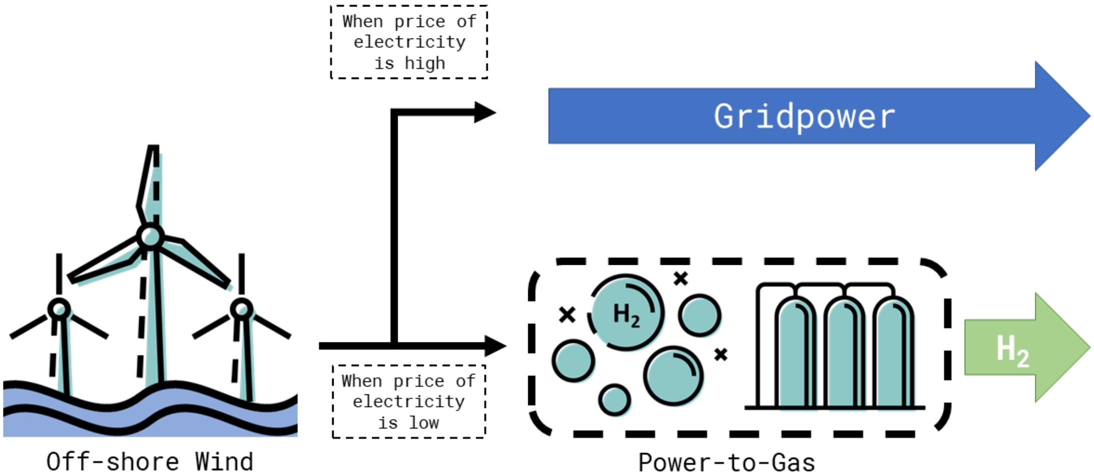

Figure 15: Illustration, Off-shore wind with PtG

The windfarm – The off-shore windfarm has an installed capacity of 100 MW. This is a fairly large windfarm although it is not among the top 50 largest off-shore wind farms in the world. The mean windspeed is 8.42 m/s and the farm annually produces 410.86 GWh of electricity, granting it a capacity factor of 46.77 %[1]

The Power-to-Gas facility – The Power-to-Gas (PtG) facility uses PEM electrolysis to produce hydrogen. The capacity of the facility is optimised so that it generates as much revenue as possible. The electrolyser, compressors and remainder of the facility require a total of 60 kWh electricity to produce one kilogram of hydrogen. The investment cost (Capex) of the PtG facility [5], [1] is governed by the equation below.

$$Capex_{PtG} = 2.3\ M€ \cdot {P_{PtG}}^{0.80}$$

Hydrogen and Electricity – Electricity is sold to the grid at market price determined by the spot price. For this analysis spot price data from Sweden SE 3 2020 is used. Hydrogen is assumed to be sold at a price of 3 – 4 €/kg H2. The overall economics of the PtG facility is highly dependent on the hydrogen price.

[1] IRENA reports an average capacity factor of 43 % for off-shore wind [28].

Results

The first step is to optimize the capacity of the PtG facility. If the price of hydrogen is high it will be profitable to have a large facility that can produce as much possible. However, if the price is low, a smaller facility or no facility at all is better. Figure 16 illustrates this relationship. At a hydrogen price of 3 €/kg H2 or less, no amount of PtG capacity will yield in an increase in the net present value. However, at 4 €/kg H2, a facility with up to 80 MW of electrolyser capacity will yield a profit.

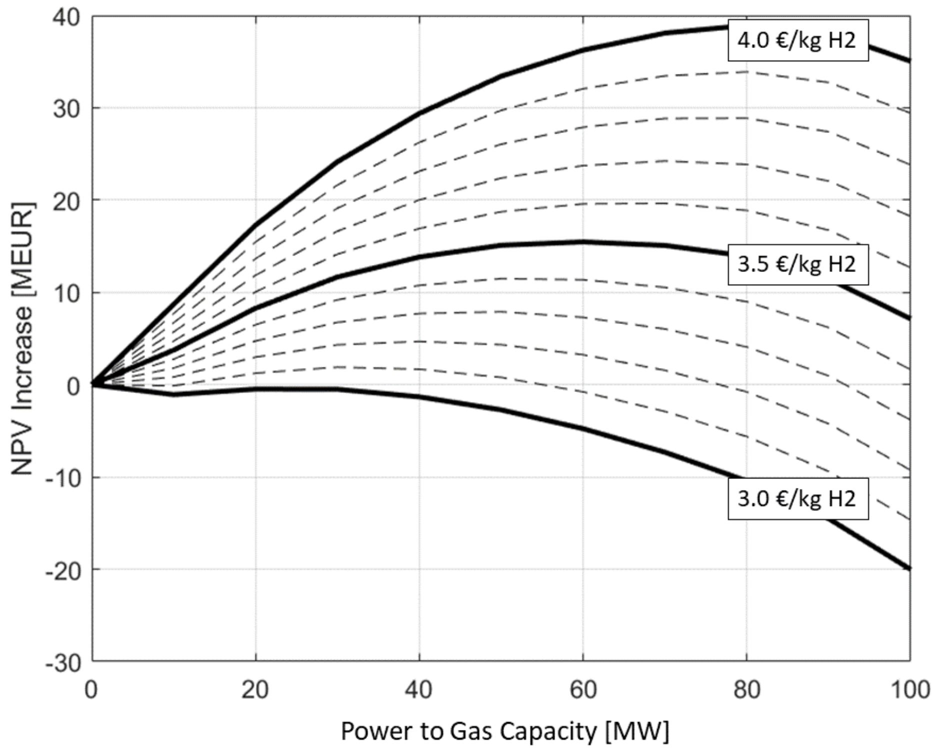

Figure 16: NPV Increase in relation to PtG capacity (Lifetime = 20 years, discount rate = 10 %)

Table 4: Results from Exhibit B

Hydrogen price	3.00 €/kg H2	3.50 €/kg H2	4.00 €/kg H2
Optimised PtG Capacity	0 MW	59 MW	81 MW
Capex PtG facility	0	60 M EUR	77 M EUR
Windfarm electricity production	410 GWh / year	410 GWh / year	410 GWh / year
Hydrogen production	0 kg H2 / year	4.77 M kg H2 / year	5.97 M kg H2 / year
Electricity to grid	410 GWh / year	124 GWh / year	60 GWh / year
Hydrogen income	0 EUR / year	16.71 M EUR / year	23.90 M EUR / year
Electricity income	9.16 M EUR / year	3.72 M EUR / year	2.02 M EUR / year
NPV Increase	0	15.5 M EUR	38.9 M EUR

Conclusion

Exhibit B shows that 100 % green hydrogen production is viable at hydrogen price of 3 €/kg H2 or higher. The Power-to-Gas facility can be very large in comparison to the windfarm if the hydrogen price is high enough. At a price of 4 €/kg H2, the PtG-facility will consume the majority (80 %) of the electricity produced by the windfarm.

Exhibit C: HRS with Green Hydrogen Production and Additional Revenues

This section will explore a business case for a HRS with its own green hydrogen production and where additional revenues can be generated from the sale of waste heat and oxygen. The HRS in this case is placed very strategically at a location close to renewable power production from wind (the HRS is connected directly to the transformer station of the wind park), close to a waste water treatment plant, which will use the oxygen from the water electrolysis and close to a housing complex which will use the waste heat. In addition, the location is frequented by FCEVs such that the hydrogen demand on average is 480 kg H2/day. The HRS is also grid connected so that grid power can be used, if necessary.

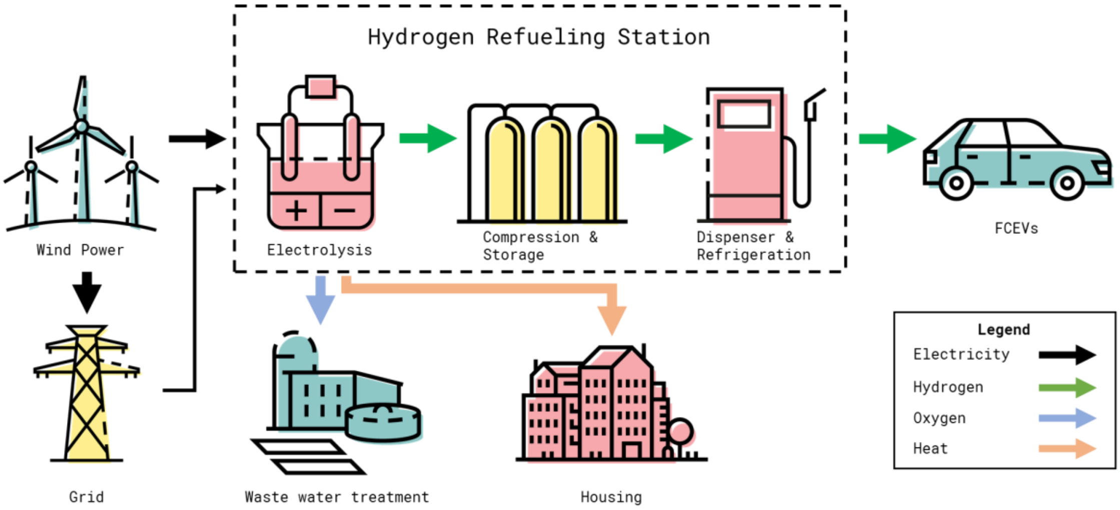

Figure 17: Exhibit C - Illustrative Schematic

Method

Design of the HRS excluding the electrolyser – For the dimensioning and cost of components for the refuelling station other than the electrolyser HRSAM[2] (Hydrogen Refuelling Station Analysis Model) is used. HRSAM is a tool which lets the user design and calculate the costs and energy use for a HRS based on certain inputs. HRSAM will, for instance, tell the user the size of compressors and hydrogen storage required for the station and estimate the cost.

In this case, the station is designed for 700 bar cascade dispensing (which is suitable for most FCEV passenger cars), 20 bar hydrogen supply to the station (the electrolyser is treated separately from the rest of the station) and a maximum dispensing rate of 600 kg H2/day. The station has two fueling hoses such that up to two vehicles can refuel simultaneously and the station is annually used up to 80% of its capacity, which means an average dispense rate of 480 kg H2/day.

The main components of the refuelling station excluding the electrolyser are the compressor, the low-pressure storage, the cascade ('buffer') storage, the dispensers and the refrigeration equipment. The dispensers and refrigeration equipment are used to refuel the FCEVs with hydrogen that is cooled in accordance with the refuelling standard SAE J2601. The cascade storage is a high-pressure storage unit, consisting of multiple storage vessels at pressures of up to 950 bar. It is the cascade storage which enables refuelling. Due to the high pressure inside the cascade storage hydrogen will flow from the station to the vehicle tank (where the pressure is lower) when connected to the station through the dispenser. The low-pressure storage is not used

[2] Hydrogen Refuelling Station Analysis Model is a tool developed by the National Renewable Energies Laboratory of the U.S. Department of Energy. https://hdsam.es.anl.gov/index.php?content=hrsam

for refuelling. It is instead used as a means to balance the storage of hydrogen over time so that the supply of hydrogen can match demand required. The compressor is used to compress the hydrogen to adequate pressures for storage inside either the low-pressure storage or the cascade, as it is connected to both (Figure 18).

For the costs of the components the setting “low production volume” is used. This corresponds to current component costs and does not include future potential cost reductions.

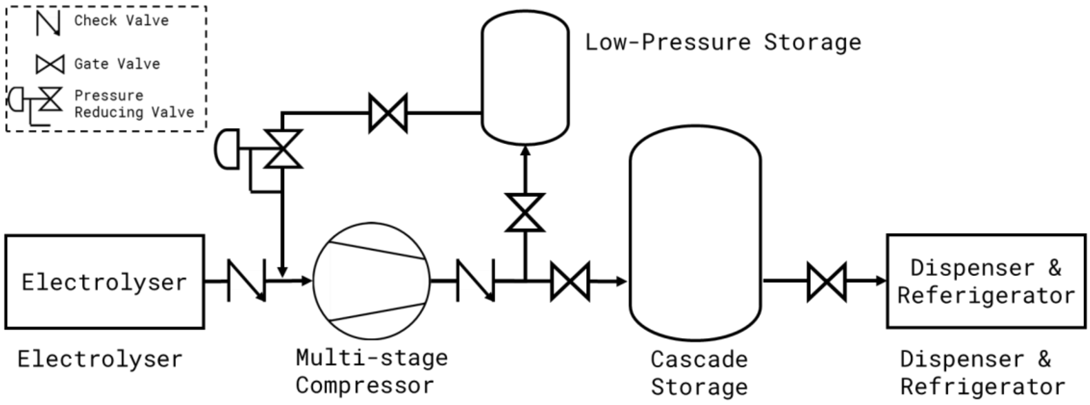

Figure 18: HRS schematic of components and hydrogen flow

Hydrogen Production – The electrolyser supplies the HRS with hydrogen. As HRSAM treats the electrolyser as a 20 bar constant supply of hydrogen with no associated costs. It is assumed that the electrolyser has an energy consumption of 50 kWh/kg H2 [3]. For every kilogram of hydrogen produced 7.92 kg of oxygen and 10 kWh of useful heat is received. If the waste heat is utilised the overall energy efficiency of the process is increased from 66.7 % to 86.7 %. The investment cost of the electrolyser is calculated by Figure 1. The annual operational and maintenance cost of the electrolyser which includes one stack replacement after 10 years is assumed to be 5 % of the capital investment.

The electrolyser is operated by the logic presented in the flow chart in Figure 19. The goal is to manage the production of hydrogen so that the HRS always has a sufficient supply of hydrogen whilst using as much wind power and as little grid power as possible. Grid power will only be used in cases where the low-pressure storage is low (less than 20 %) and there is no wind available. In those cases only enough power to meet the current demand of hydrogen is used.

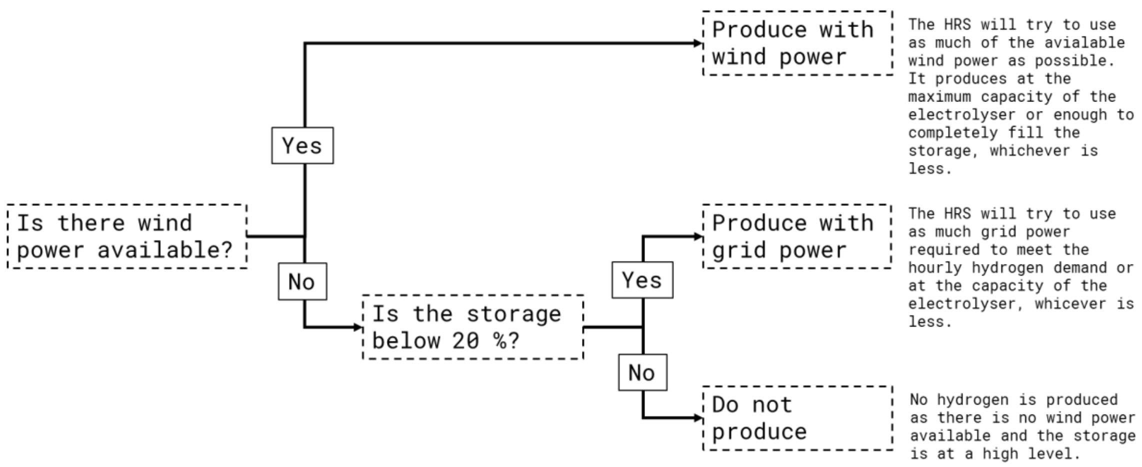

Figure 19: Hydrogen production logic flow chart

Wind power – The HRS is connected directly to an on-shore wind park which supplies to majority of electricity to the station. The wind park has a capacity of 20 MW and any power it produces will primarily go to the HRS and any excess is sold to the grid. As the wind park is much larger than the HRS the majority of its produced electricity will go to the grid and not the HRS.

A Weibull distribution model is used to generate artificial wind speed data which is used to simulate the power production of the wind park. For the Weibull distribution the shape parameter is set to 2 and the scale parameter is set to 8. The distribution of the wind speeds used in the generated data set is illustrated in Figure 20. The mean wind speed is 7.04 m/s. For the calculation of power output from the wind park, the power curve in Figure 21 is used. The capacity factor of the wind park is 35.67 %.

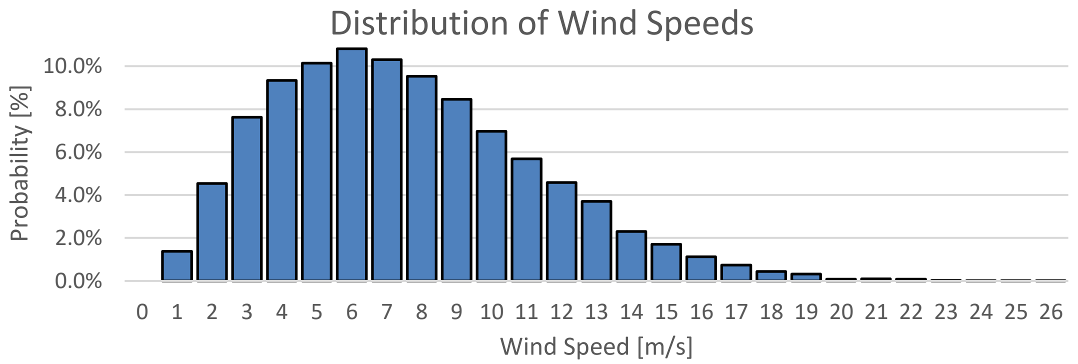

Figure 20: Distribution of Wind Speeds

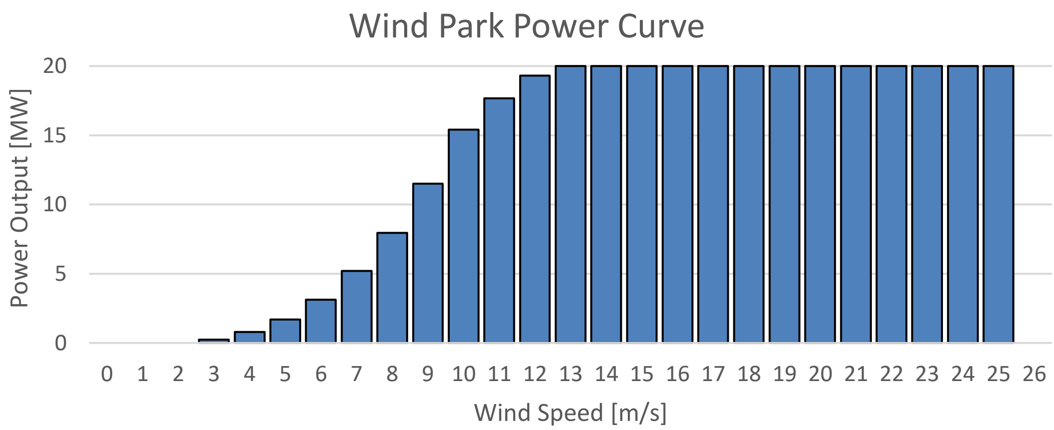

Figure 21: Wind Park Power Curve

Energy costs and financial – For the cost of electricity, the following is assumed: Electricity from the wind park costs 40.30 €/MWh, which is the levelised cost of electricity in Sweden as of 2019 according to IRENAs statistics [23]. Since the HRS is directly connected to the transformer station of the wind park, no transmission fee is paid for this electricity. As for the electricity from the grid, it is assumed to cost 48 €/MWh, based on the average Swedish electricity price in SE3 from 2019 to 2020 including a transmission fee. The electrolyser is exempted from energy tax but for all other components, a tax of 36.50 €/MWh is applied. For the capital costs, an asset lifetime of 20 years and a discount rate of 5 % is assumed. 15 % of the installed capital is assumed for the commissioning cost including, but not limited to, engineering, permitting, planning and construction. The conversion rate from USD to EUR used is 0.877. The income for selling oxygen and heat is assumed to be at most 50 €/ton O2 and 50 €/MWh heat respectively.

Results

Design and Dimensioning – With the prescribed inputs, HRSAM presents the following design: A compressor with a capacity of 33 kg H2/h, low-pressure storage of 248 kg H2, cascade storage of 362 kg H2 and two fuel dispensers with refrigeration units. However, since HRSAM assumes a constant 20 bar supply of hydrogen, the low-pressure storage is not properly dimensioned for the variable hydrogen supply that the electrolyser will give. Because of this, the low-pressure storage is increased to a capacity of 400 kg H2. Out of these 400 kg H2, only 75 % can be used for this purpose as a minimum pressure level must be maintained for the compressor.

As for the electrolyser, it is dimensioned to meet the maximum dispensing rate of the HRS of 600 kg H2/day. With the assumed efficiency of 50 kWh/kg H2, this requires an electrolyser of 1250 kW. This also means that the electrolyser has a maximum capacity of 25 kg H2/h. The overall dimensions of the components is summarized in Table 5.

Table 5: Component Dimensionsof the HRS

Component	Capacity	Energy Use
Electrolyser	1250 kW	50 kWh/kg H2
Compressor	33 kg H2/h	4.33 kWh/kg H2
Low-Pressure Storage	400 kg H2	-
Cascade Storage	362 kg H2	-
Dispenser	2 Dispensers	-
Refrigeration	2 HX/condensing units	0.58 kWh/kg H2

Energy Usage – The wind power and hydrogen production was simulated for the full 8760 hours of a year. During the simulated year, the wind park produced a total of 124.5 GWh of electricity and the electrolyser produced a total of 175 100 kg H2. The available wind power and low-pressure storage is enough so that barely any grid power has to be used. Only 65 out of the total 8760 hours used for the production of hydrogen comes from grid power. Figure 22 illustrates such an occasion when grid power is used. The lowest level of storage required is 6 % of the usable space in the low-pressure storage.

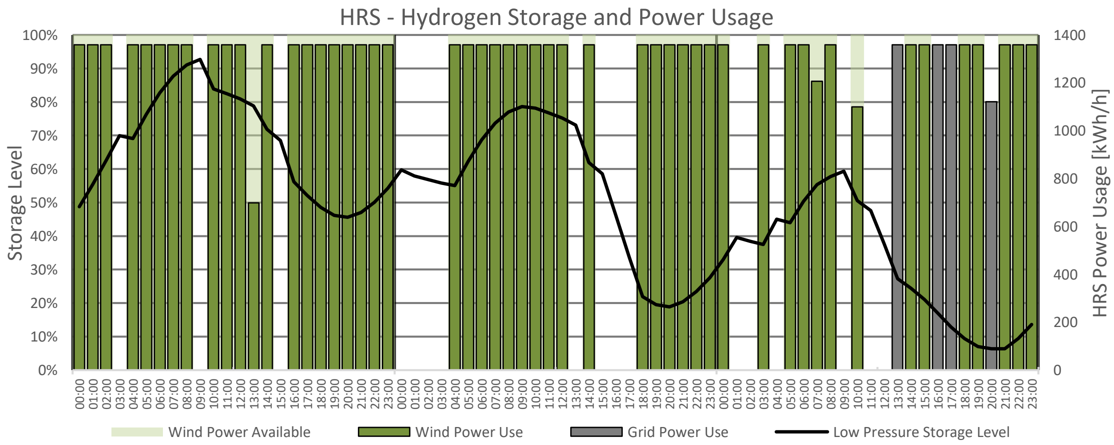

Figure 22: Example operation of three days for the HRS. Grid power is only rarely used

In total, the electroloyser and compressor is supplied with 9.5 GWh of electricity and only 0.4 % of it comes from the grid. The refrigeration system used to cool the hydrogen when delivered to the vehicles is assumed to only use grid power as it must be operationally independent from the access to wind power. It does, however only consume 102 MWh, which is only 1 % of the total electricity usage of the HRS. Figure 23 illustrates the full flow of electricity from the wind park and grid to the main electricity-consuming components of the HRS, as well as the flow of electricity from the wind park to the grid, which is by far the largest.

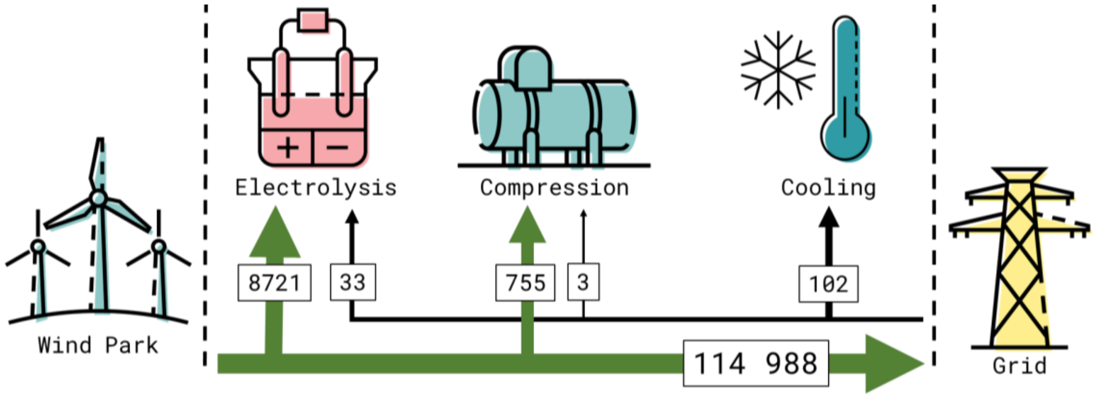

Figure 23: Flow of electricity measured in [MWh/year]

Costs – The total investment cost of the HRS including commissioning is estimated to be 4.30 M€. Maintenance and operational costs (O&M) are calculated to be around 206 000 €/yr and energy costs (wind power, grid power and energy tax) are 418 000 €/yr. Detailed cost information is presented in Table 6.

Table 6: HRS Costs

Component	Capital [€]	O&M [€/yr]	Wind [€/yr]	Grid [€/yr]	Tax [€/yr]
Electrolyser	1 064 838	53 242	351 914	1 082	-
Compressor	949 013	68 657	30 476	94	27 671
Low-P. Storage	508 055	27 194	-	-	-
Cascade Storage	664 184	24 611	-	-	-
Dispenser	223 052	9 446	-	-	-
Refrigeration	211 812	11 088	-	3 351	3 707
Electrical	75 122	3 181	-	-	-
Controls/Other	87 719	8 912	-	-	-
Commissioning	567 569	-	-	-	-
Total	**4 351 363**	**206 330**	**382 389**	**4 527**	**31 378**

The balance sheet in Table 7 presents the overall costs and incomes of the HRS. The HRS produces and dispenses 175 100 kg H2 annually. At the same time, it produces 1 386 792 kg O2/yr of oxygen and 1 751 000 kWh/yr of useful heat. If the proceeds from oxygen and heat is zero, the levelized cost of hydrogen delivered to the vehicles (LCOH) becomes 5.56 €/kg H2. If the highest possible proceeds for both heat and oxygen can be generated, the LCOH becomes 4.67 €/kg H2, which is a 16 % decrease in the cost of hydrogen.

Table 7: Balance sheet and levelized cost of hydrogen

Oxygen Profit [€/ton O2]	**0**	**25**	**0**	**25**	**50**
Heat Profit [€/MWh]	**0**	**0**	**25**	**25**	**50**
Annual Capital Cost [€/yr]	349 165	349 165	349 165	349 165	349 165
O&M Cost [€/yr]	206 330	206 330	206 330	206 330	206 330
Energy Cost [€/yr]	418 294	418 294	418 294	418 294	418 294
Oxygen Income [€/yr]	0	34 670	0	34 670	69 340
Heat Income [€/yr]	0	0	43 775	43 775	87 550
Total Cost - Income [€/yr]	973 788	939 118	930 013	895 343	816 899
LCOH [€/kg H2]	**5.56**	**5.36**	**5.31**	**5.11**	**4.67**

Sensitivity Analysis – The main objective of this business case is to study and quantify the economic impact it may have on a HRS if the by-products of oxygen and waste heat can be utilised. However, these are only two out of the many variables which may have a large impact on the overall economics of an HRS. In this section, the impact of three such variables are examined. The variables are total capital costs, daily average hydrogen demand and the price of wind electricity. Each variable is increased or either decreased by 10 %. The results, measured as overall change in LCOH (excluding revenues from oxygen and heat) are presented in Figure 24.

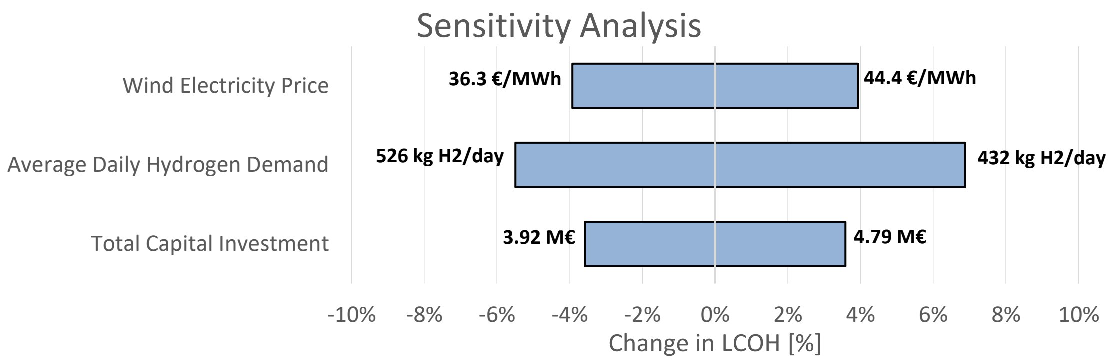

Figure 24: Sensitivity Analysis of three variables

Discussion & Conclusion

In this business case, it was shown that with the additional revenue sources from heat and oxygen, it is possible, in an optimal case, to reduce the selling price of hydrogen from 5.56 €/kg H2 to 4.67 €/kg H2, that is a reduction of 16 %, under an optimal case scenario. The optimal case assumes that all of the useful waste heat and oxygen can be sold at market value for 100 % profit. It is, however, unlikely that such would be the case for any real HRS. The by-products can in reality will not be to be sold at full profit as there will be some cost associated with the harvesting of the by-product, such as piping for the oxygen or heat exchangers for the heat. It is also not certain that all of the by-product can be sold at all times. For instance, most buildings will have a higher demand for heating in winter and a much lower demand in summer. This means that the heat produced by the electrolyser in summer might not be able to be sold. In a more realistic case where only parts of the heat and oxygen can be sold, the impact will be much less. Table 7 shows that a more realistic hydrogen price would lie between 5.11 and 5.36 €/kg H2, which corresponds to cost reduction of 3.5 - 8 %.

The underlying assumption for this business case is that both the oxygen and waste heat can be utilised nearby the HRS. These circumstances should not be assumed to be commonly applicable for all HRS's. In many of the strategic locations for HRS, such as along highways, it will be unlikely to find any demand for oxygen and waste heat in the vicinity. In this case, the most economical option would likely be to vent the oxygen and cool off the heat as the cost associated with harvesting of those by-products would far outweigh the benefits, as discussed earlier in this report.

The sensitivity analysis showed that relatively modest changes in some key variables may have impacts on the overall LCOH, which are just as large as the possible gains from oxygen and heat. For instance, an increase in hydrogen demand by 10 % reduces the LCOH by 5.5 %. This increase in demand equates to 48 kg H2/day, which is about the same amount of hydrogen as it is estimated to refill one FCEV long haul truck fuel tank in the future. This implies that in the larger picture, the revenue from oxygen and heat are only secondary in importance, compared to variables such as those investigated in the sensitivity analysis. For an operator of an HRS, this means that the choice of location for constructing the HRS should be decided primarily based on factors such as hydrogen demand and electricity price. It will unlikely be worthwhile investment choosing a location with higher electricity prices, simply because it is possible to sell oxygen and waste heat there.

Exhibit D: Hydrogen Production from Variable Renewable Electricity Only

This exhibit will examine how green hydrogen can be produced in a cost-optimal way from variable renewable electricity sources, such as wind or solar, in isolated regions, where connection to the main electrical grid is not feasible. Three different sources of variable renewable electricity are compared: solar power installed in Sweden, solar power installed in Spain and "general" wind power.

Model

A simulation model for the hydrogen production system was developed in Simulink. The system consists of a variable renewable electricity source, which can be either wind or solar. The electricity is fed to the electrolyser, which produces hydrogen. The hydrogen is stored directly in a hydrogen storage container (compression is ignored in this case). From the hydrogen storage, a constant output of hydrogen is prescribed as the hydrogen demand. The goal is to design this system so that the investment cost for the entire system is as low as possible, whilst ensuring that the storage is never empty. The simulation run for 26 280 timed steps where each step represents one hour.

The variable renewable electricity production can be set as either wind or solar power. The electricity production is modelled as a function of time. For solar power, the online tool, PVGIS [24] is used with the chosen timespan of 2013 – 2016 and with Lund, Sweden or Madrid, Spain as the locations. For wind power, the same method as in exhibit C is used. The functions are illustrated in the figures 26 - 28. All of these functions can then be multiplied by a scalar factor so as to represent either an increase or a decrease in installed capacity of the electricity source.

The produced power is then fed to the electrolyser, which will use as much of the available power as possible to produce hydrogen. It cannot, however, use more than its maximum capacity and over-produce hydrogen such that the storage overfills.

The is defined as the sum over time of the hydrogen production, subtracted by the hydrogen demand. The initial condition for the storage is that it starts with a full capacity.

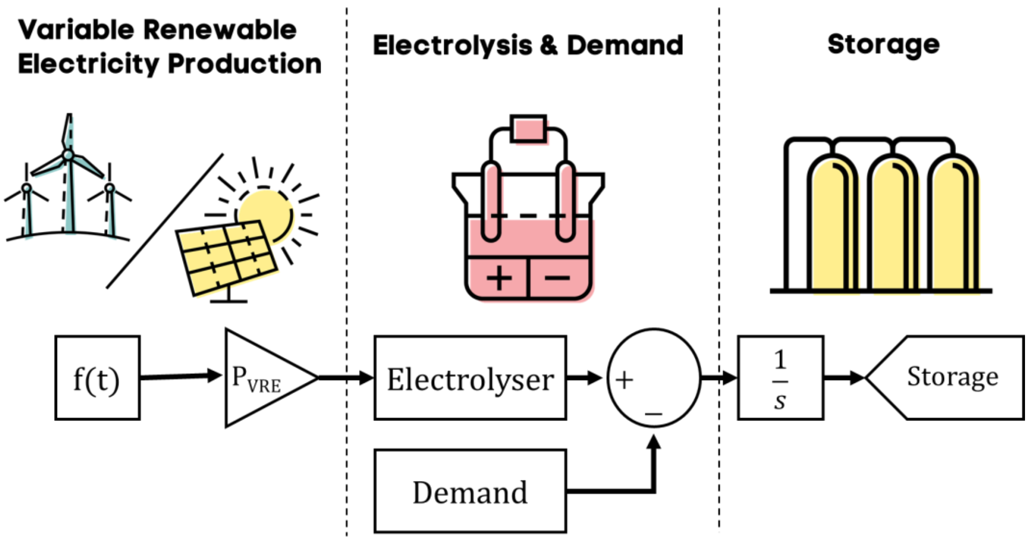

Figure 25: Overview of the studied hydrogen production system

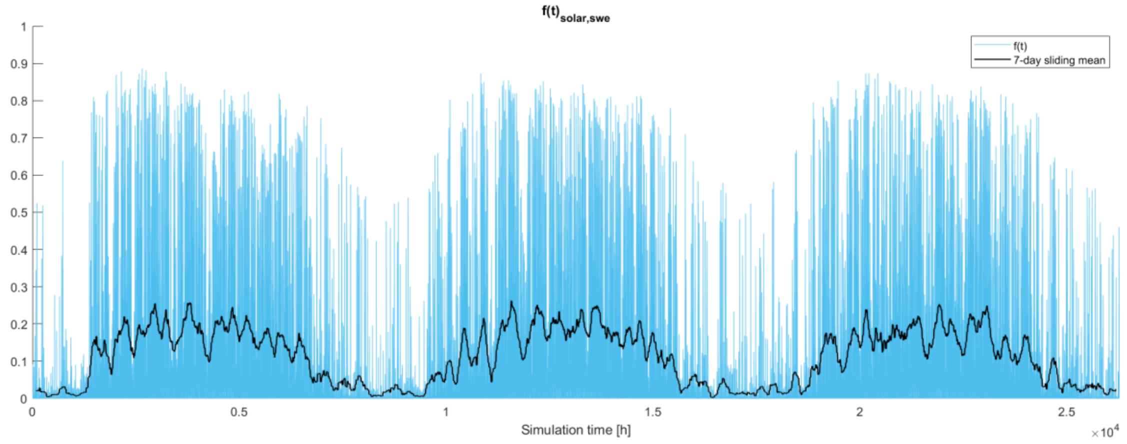

Figure 26: Function for Swedish solar power with sliding mean value

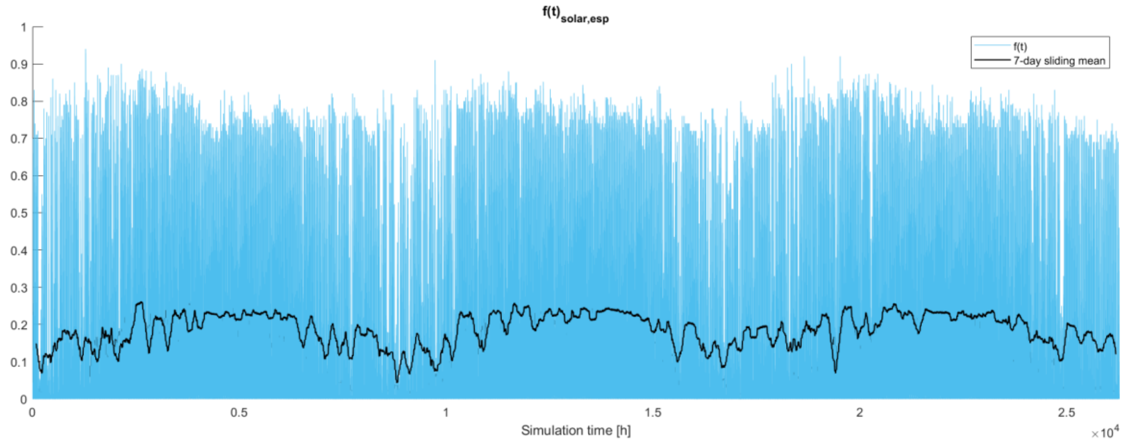

Figure 27: Function for Spanish solar power with sliding mean value

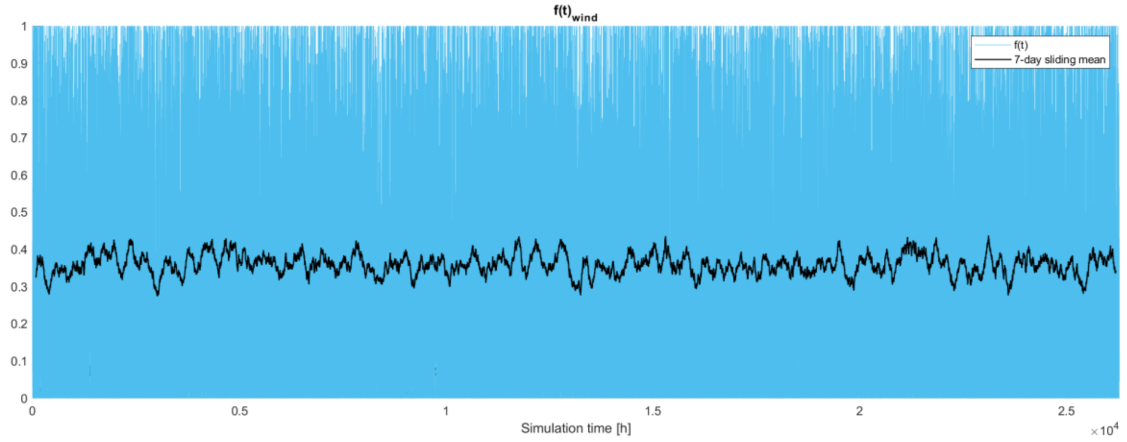

Figure 28:Function for wind power with sliding mean value

Optimization Method

The optimization of the system is done numerically and in several steps. First, a value for the installed capacity of the variable electricity source is chosen before selecting a value for the capacity of the electrolyser. After this, a minimum required storage size can be calculated by iteration for the given combination of electricity source and electrolyser. Once the value for the installed capacity, electrolyser and storage is determined, a cost for the system can be calculated. These calculations are then repeated for multiple configurations of the system, resulting in the lowest cost configuration being chosen.

$$Total\ Cost = P_{VRE} \times C_{VRE} + P_{EL} \times C_{EL} + S_{Storage} \times C_{Storage}$$

A range of power production and electrolyser combinations are searched. The searched ranges for wind and solar are presented in the figures 29, 31 & 33 below. The criterion for the power production and electrolyser capacity combination is that it must be able to produce at least as much hydrogen as the hydrogen demand on average over time. Also, the electrolyser cannot be larger in installed capacity than the power source.

Table 8: Used variables and assumptions

Symbol	Description	Value
$f_{wind}(t)$	Variation in wind production over time	$0 \leq f_{wind}(t) \leq 1$
$f_{solar,swe}(t)$	Variation in solar production over time (Sweden)	$0 \leq f_{solar,swe}(t) \leq 1$
$f_{solar,esp}(t)$	Variation in solar production over time (Spain)	$0 \leq f_{solar,esp}(t) \leq 1$
CF_{wind}	Mean value of $f_{wind}(t)$	35.9 %
$CF_{solar,swe}$	Mean value of $f_{solar,swe}(t)$	11.2 %
$CF_{solar,esp}$	Mean value of $f_{solar,esp}(t)$	18.6 %
P_{VRE}	Installed Variable Renewable Electricity Production Capacity	Variable
P_{EL}	Installed Electrolyser Capacity	Variable
$H2_{Demand}$	Hydrogen demand	$2\ kg\ H2/h$
E_{El}	Electrolyser Power Use [5]	50 kWh/kg H2
$S_{Storage}$	Installed Hydrogen Storage Capacity	-
$C_{VRE,Wind}$	Wind Power Installation Cost [25]	1190 €/kW
$C_{VRE,Solar}$	Solar Power Installation Cost [25]	775 €/kW
C_{EL}	Electrolyser Installation Cost [5]	1000 €/kW
$C_{Storage}$	Hydrogen Storage Installation Cost [8]	475 €/kg H2
r	Discount rate	5 %
L	Asset Lifetime	20 years

Results

Solar – Sweden

In the case of Swedish solar power, it was found that storage of size 4400 – 5000 kg H2 is required, depending on the combination of power production and electrolyser (**Error! Reference source not found.**). This very large storage capacity is required to handle the seasonal variation in solar power production which is significant. Figure 30 shows how the level of hydrogen inside the storage varies over the seasons, peaking at summer and reaching its lowest point during winter.

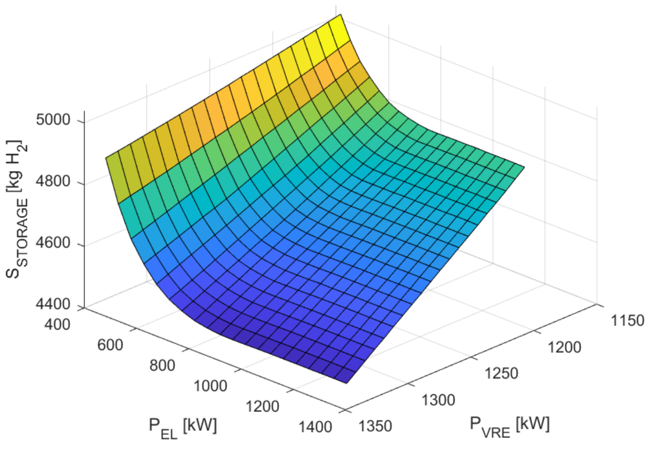

Figure 29: Minimum required storage for solar in Sweden

The most optimal configuration was found to be 1251 kW of solar power with an electrolyser capacity of 473 kW and a storage capacity of 4835 kg H2. This comes at an investment cost of 3 793 000 € which results in a LCOH of 17.10 €/kg H2.

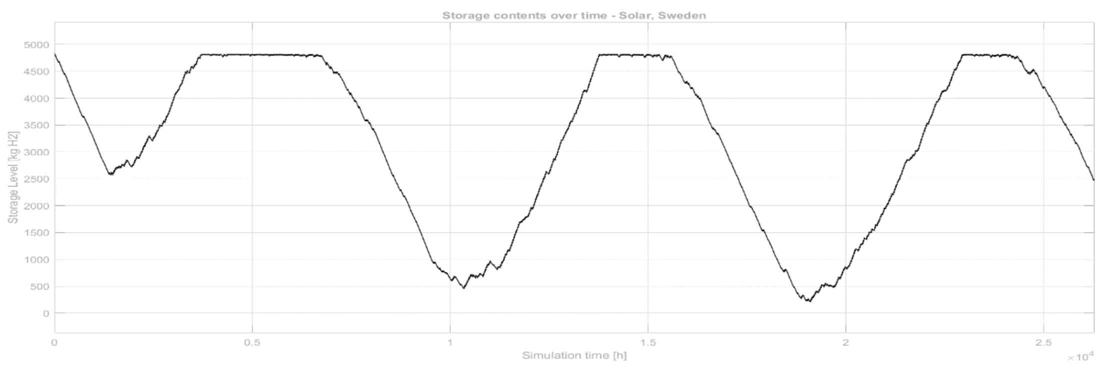

Figure 30: Storage Contents over time for the most optimal Swedish solar configuration

Solar – Spain

For the Spanish solar power, it was found that a much smaller storage is sufficient, between 200 and 1600 kg H2. The required storage depends largely on the electrolyser capacity, as illustrated by Figure 31, where smaller electrolyser capacities require the larger storage space.

In Spain the seasonal variations in solar power are much less significant than in Sweden. This explains the lack of observable seasonal variations in the storage level as illustrated by Figure 32.

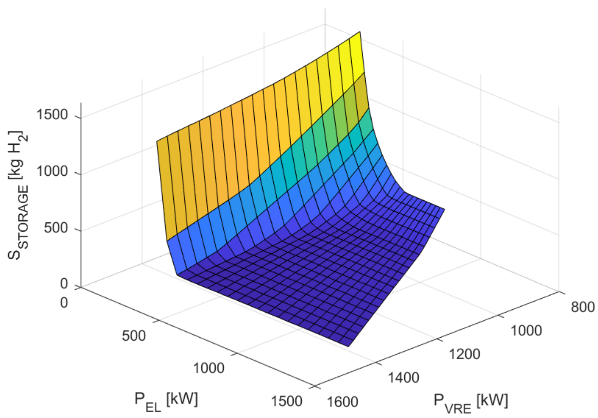

Figure 31: Minimum required storage for solar in Spain

The most cost optimal configuration for the system was found to be 902 kW of solar power, 480 kW in electrolyser capacity and 387 kg H2 in storage capacity. This results in an investment cost of 1 362 000 € and a LCOH of 6.20 €/kg H2.

Figure 32: Storage Contents over time for the most optimal Swedish solar configuration

Wind

For the wind-based hydrogen production, a storage of 60 – 150 kg H2 is required (Figure 33). No seasonal variations are observed and the storage is only needed to bridge the momentary gaps where wind power production is low (Figure 34).

The most optimal configuration was found to be 315 kW of wind power, 231 kW in electrolyser capacity and 91 kg H2 of storage capacity. The investment cost for this is 649 000 € and the LCOH 2.97 €/kg H2.

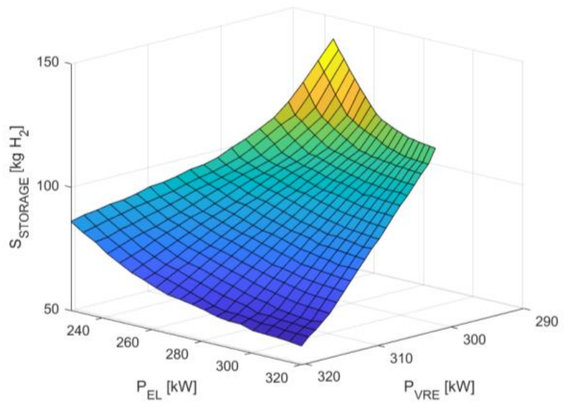

Figure 33: Minimum required storage for wind

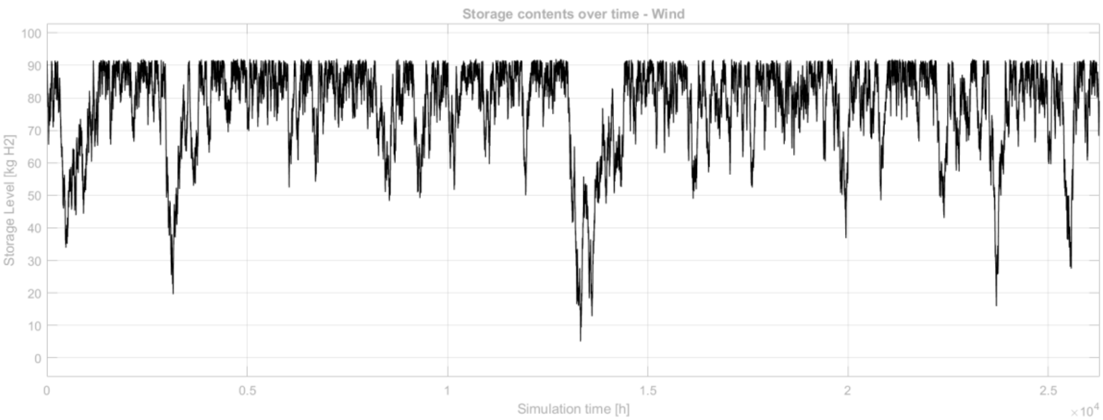

Figure 34: Storage Contents over time for the most optimal wind configuration

Comparison and Conclusion

The difference in cost between the three options is significant. Wind is able to produce hydrogen at half the cost ofusing Spanish solar power and at less than a fifth of the cost ofthat using Swedish solar power.

A key factor behind the costs is the required storage space (Figure 35). Between the Swedish and Spanish solar options, the most significant difference comes from the required storage space, which in the Swedish case, arises due to the seasonal variations. In Spain where those variations are not as noticeable, smaller storage space is possible.

Another important factor is the capacity factor of the electrolyser (as explained in earlier sections of the report). Based on the solar options, it was found that an electrolyser capacity of around 470 – 480 kW is the optimal. With such an electrolyser, ta daily production of hydrogen of averagely 2 kg H2/h has only a capacity factor of around 20 %. For wind-power, it is possible to have a smaller electrolyser with a much higher capacity factor of 43 %.

In all three cases, it was found that it is more cost efficient to have an over-production of electricity from the variable renewable electricity sources. The required electricity to produce 2 kg H2/h for a year is only 876 MWh/yr but the different options will produce between 989 and 1469 MWh/yr. Since the system is off-grid and there are no other users for this electricity, it is assumed that surplus electricity is lost. If the system were, however, connected to the grid or if there are other potential consumers for the surplus electricity, additional revenues could be generated through selling the excess electricity. This would potentially strengthen the case for Spanish solar power.

Table 9: Comparison of most optimal solutions

Parameter	Solar - Sweden	Solar - Spain	Wind
P_{VRE}	1251 kW	902 kW	315 kW
P_{EL}	473 kW	480 kW	231 kW
$S_{Storage}$	4835 kg H2	389 kg H2	91 kg H2
$Total\ Cost$	3 793 000 €	1 363 000 €	649 000 €
$Electrolyser\ Capacity\ Factor$	21 %	21 %	43 %
$Unused\ Produced\ Electricity$	355 MWh/yr	593 MWh/yr	113 MWh/yr
$LCOH$[3]	17.10 €/kg H2	6.24 €/kg H2	2.97 €/kg H2

[3] Only including investment costs for renewable power, electrolysis and storage

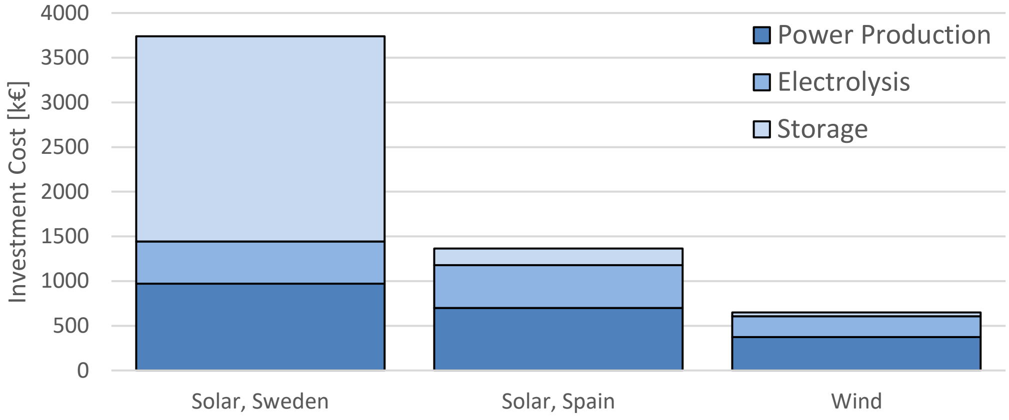

Figure 35: Distribution of investment costs

Lessons Learned

Multiple projects about hydrogen and hydrogen refuelling stations have been undertaken by the HyTrEc2 partners during the past few years. This includes business cases, a Master´s Thesis and demonstration projects.

In this section of the report, some of the findings from these projects related to hydrogen production, distribution and refuelling stations are presented.

- **Municipality of Groningen** – Description and Experiences from early HRS demonstrator
- **RISE** – Master´s thesis about solar powered hydrogen refuelling stations
- **Province Drenthe** – Business case for Hydrogen refuelling stations
- **Aberdeen City Council** – Hydrogen Supply Hub Business Case
- **Aberdeen City Council** – Description and Experiences from early HRS demonstrator

Municipality of Groningen – Experience from early HRS implementation

HyTrEc2 partner Groningen is home to some of the earlier hydrogen refuelling developments among cities in Europe. The first HRS was built in 2017, with new HRS developments continuing during 2021 and 2022. Several companies are already participating in Groningen's hydrogen economy, such as Shell, Hyzon motors and Holthausen Energy Points amongst, among others. Also, the Municipality of Groningen itself is a key player in the local hydrogen economy and has been leading hydrogen developments in the region. By working together with local authorities and private companies the City of, Groningen has advanced from having only one small HRS, with only limited access, to a fleet of more than 40 hydrogen vehicles (expected in 2022) operating on its streets. Here, HyTrEc2 project partner, the Municipality of Groningen, shares some of their experiences with their first hydrogen refuelling station that was built in 2017.

Groningen's First Hydrogen Refuelling Station

The station was built in 2017 but back then, it did not consist of much more than a compressor for hydrogen. Hydrogen was bought and imported to the station for dispensation.. Over time, the station was upgraded with an electrolyser, solar panels and cascade storage. The solar panels, which were built over an old landfill site, supply, supplies the electrolyser with renewable electricity, ensuring green hydrogen production. The cascade storage, which is the newest addition to the station, enables much faster refuelling to of the vehicles. The station has only one dispenser and is, very small relative to the future HRS developments in Groningen, with capacity to refill only up to 19 FCEV passenger cars daily[4].

The HRS is private, and the public does not have direct access to it. The station is behind a by fence and the company that owns the station provides access rights to the station on an individual pre-arranged agreement basis. The company that owns the station financed the investment and operational costs for the station, whereas the Cascade storage was financed by a subsidy. Initially, the price of hydrogen was above 15 €/kg H2 but has since dropped to 10 €/kg H2 (ex. VAT).

[4] A passenger car such as the Toyota Mirai has a fuel tank of approximately 5 kg H2.

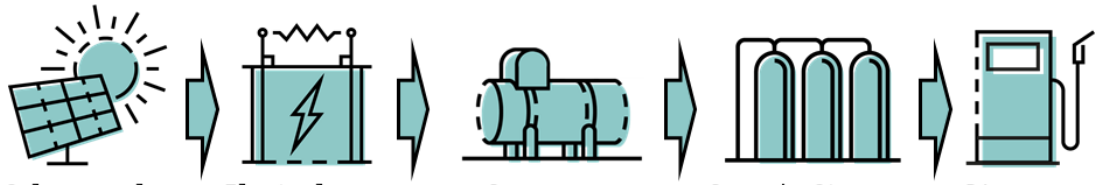

Figure 36: Station layout as of 2019

Shell Hydrogen Refuelling Station

A new HRS was inaugurated in Groningen in June 2021. This new HRS is one of the largest in Europe and is accompanied by a fleet of 20 hydrogen buses. The station was built by Shell, which also delivers green hydrogen to the station via trailer [26]. However, this station is only meant to be used by the 20 buses and is not open to the public. The buses use 350 bar refuelling, which means that the station is only capable of 350 bar refills.

The new public HRS

In the near future (Q3/Q4 2021), a new HRS will open in Groningen. This HRS is much larger than the first HRS and is capable of quickly refilling for a larger vehicle fleet. The station will be owned and operated by the private company "Holthausen Energy Points" and a vehicle fleet of 15 vehicles, owned by the Municipality of Groningen, will accompany the station in the initial phase. The vehicle fleet will mostly consist of utility vehicles, such as trucks (manufactured by Hyzon motors and E-trucks). Other than the regular vehicles, an entirely new type of vehicle will be tested and operated, that is hydrogen cargo bikes.

The HRS will have two hydrogen dispensers, both capable of 350 bar and 700 bar refills. There will also be an additional "special" dispenser for 300 bar, to cater for the cargo bikes. Each dispenser has a capacity of 47 kg H2/h, giving the station a total theoretical capacity of 2256 kg H2/day, which is more than 20-times the capacity of the first HRS, and may well be considered as a full-scale station.. The new station will have its own small electrolyser, but will also source green hydrogen produced in a nearby town (Veendam) and produced at the 2017 HRS.

Project Experience and Advice

In this section, the Municipality of Groningen shares some of their experience from the first HRS project and gives advice for the future.

Things take time, often longer than you think – There are many things which may slow down development, particularly concerning permits. The relevant authorities for issuing of permits often lack working experience with hydrogen, making the process very slow. In the case of Groningen, the RDW (Netherlands Vehicle Authority) has taken a while to issue in issuing the permits for both hydrogen vehicles and machines. Since these machines are non-standard equipment, the process for permitting is ill-defined and requires extra time.

Include relevant authorities from the beginning – Groningen has been working with their local fire department from day one of the project to ensure that the safety and permitting work of the fire department would be as quick and easy as possible. This has indeed been successful. Attempts were made to also include the RDW in the project, but RDW was unable to participate to the extent that is required, hence led to the aforementioned issues.

Plan for safety – Hydrogen vehicles and refuelling stations require safety precautions, in addition to those required for battery-electric or fossil fuels vehicles. For instance, special precautions are required for the parking of hydrogen vehicles in indoor garages. These precautions state that a certain amount of ventilation is required to avoid the build-up of hydrogen gas, in case of a leakage of hydrogen from the vehicle. Further, hydrogen detection equipment and elimination of possible ignition sources (such as electrical sparks) are required. The municipality of Groningen plans for this when new buildings are constructed so that they are already safe for hydrogen right from the beginning.

Conclusion

The Municipality of Groningen's project is a good example of how a coalition of private and public actors can work together. Very few single actors can cover the full supply chain of producing renewable electricity for the electrolysers, producing green hydrogen for the refuelling stations, operating the refuelling stations, operating the vehicles and so on. In Groningen, private companies have developed and operated the refuelling stations while the municipality has operated the vehicles. This strategy distributes both the risks and rewards of such a project between all the involved parties. In addition, making sure that the relevant authorities are included from the beginning has proven to improve the process.

Table 10: Timeline for HRS developments in Groningen

Year	Events
2016	Project start
2017	The initial HRS is built by the beginning of the year. At this point the station is very simple and mostly consists of a hydrogen compressor. Refills are slow. Hydrogen is at this point imported to the station. By the end of the year and in early 2018 the HRS is upgraded with an electrolyser (Capable of producing 95 kg H2/day). The electrolyser is powered by a 43 000 m2 solar park.
2019	In early 2019 the HRS is upgraded with cascade storage. This storage can store hydrogen at multiple pressure-levels and enables much faster refills than just a compressor. In total there is 140 kg H2 worth of cascade storage.
2021	In June 2021 a new HRS built by Shell is inaugurated. The station is only for the use of refilling 20 FCEV buses which accompany the station.
2021	In late 2021 a new HRS was built by HOLTHAUSEN Energy Points. The HRS has its own electrolyser capable of producing 192 kg H2/day but the station also is supplied with hydrogen from the first HRS and from the nearby region. The station is capable of the standard 350 bar and 700 bar refills in addition to a specialized 300 bar refill for hydrogen cargo bikes. The station can refill a total 94 kg H2/h.
2022	By 2022 the municipality will have over 40 Hydrogen vehicles in operation. The vehicles comprise: 6 cars, 20 vans, 15 trucks and the remainder are mixed machines.

RISE – Master´s Thesis about solar powered HRS

The master's thesis "Business Case, Design and Simulation of Solar Powered Hydrogen Refuelling Stations uses computer simulation to investigate the inner workings of Solar Powered Hydrogen Refuelling Stations (Solar-HRS). The thesis analyses how Solar-HRS can be designed cheaper and more efficiently. The thesis also explores some of the possibilities Solar-HRS to generate additional revenues such as by selling excess electricity from its solar panels, selling excess hydrogen to industrial appliances or by providing grid-services.

The main question of the Master´s thesis is to investigate how the economic viability of Solar-HRS can be improved. Currently, Solar-HRS as a stand-alone, are usually not profitable. The primary reason for this is the lack of demand for hydrogen. Simply put, there are too few customers. Another reason is the reliance on technologies that are still developing, such as electrolysis and large-scale storage of hydrogen.

The approach is to gain an underlying understanding of how the Solar-HRS works as a full system. With this understanding, both the economics and function of the system can be improved. Some examples of questions that were investigated:

- What components and activities carry the largest costs?
- How can the reliance on grid electricity be reduced?
- How can it be made sure that the HRS is always able to deliver hydrogen when needed?

The thesis also investigates the possibilities and potential economic value of a Solar-HRS participating in other business activities. Potentially, by generating additional revenue sources, the overall profitability of the HRS can be increased. The business options explored are:

- Selling electricity to the grid
- Providing grid-stabilizing services
- Providing back-up power during blackouts
- Utilising heat from the electrolyser and fuel cell to save heating costs
- Selling excess hydrogen to nearby industry
- Injecting excess hydrogen to the natural gas grid

Results & Findings

One of the take-aways from the thesis is that it is currently difficult to build a Solar-HRS that would be cost competitive compared to fossil-based transportation. This is unsurprising as hydrogen mobility is still developing and petrol/diesel has had plenty of time to mature. Solar-HRS that use a mix between solar power and grid power have the best chance of being cost competitive, whereas it is more challenging for off-grid stations to be cost competitive. The thesis found that it could, for example, be possible for the investigated Solar-HRS to be cost competitive if the user demand is at least 20 FCEV taxis, and that station is 80 % powered by grid and 20 % by solar power.

For a HRS to be economical, the output volume of hydrogen must be relatively large. This output will require a large supply of power. Some of this power demand can be supplemented by electricity generated by solar panels easily, efficiently and economically. The most economical solution was to build stations that are primarily grid-based and partially complemented by solar power. This may be a less environmentally-friendly option compared than a full grid-based solution, depending on the “cleanliness” of the grid power as some place may result in an unacceptable level of carbon footprint for the hydrogen. For proper analysis, a full Life Cycle Analysis (LCA) should be conducted for the case.

Fully off-grid stations have a longer way to go in terms of economic viability. They are however, an interesting option for isolated and rural communities where access to grid power is limited. The station could supply hydrogen, electricity and heat to the community. The difficulty lies in establishing a stable supply of energy as solar power is inherently an unreliable resource. If consistency is desired, the station must be built in a largely redundant way which is costly. However, if some inconsistency is acceptable, the station maybe built at a much cheaper cost.

As for the additional sources of revenue, the overarching conclusion is that most of the listed options are often unpractical and the possible reimbursement would be, at best, low and not to mention inconsistent. It is interesting to further explore these options as technology matures and develops. However, as for now, they are not useful in an economical sense. The one option that seems the most promising is to sell excess electricity from the solar panels.

Province Drenthe – Business Case for HRS

As a part of the HyTrEc2 partnership programme, the province of Drenthe has created a business case for the realisation of a Hydrogen fuel station in the province of Drenthe. The report contains both a quantitative analysis on the cost of operating the station and some qualitative insights, such as the type of permits required to realise the station.

The report explores four scenarios in which a hydrogen refuelling station (HRS) can be realised so that it can supply 10 Fuel cell hydrogen buses in the region. It is set as a requirement that the station is to be self-reliant in the supply of hydrogen, that the hydrogen is to be produced locally via electrolysis and not imported from external sources. The scenarios considered different combinations of solar, wind and grid electricity to supply the station.

For the feasibility study, cost estimates and technical parameters are based on interviews with market parties and a variety of document research, including the IEA "Future of Hydrogen". Findings from the studies were checked in cooperation with market parties. The report then uses a simulation model to calculate the hydrogen output of the HRS.

Results and Findings

The report finds that the main cost components for the station are investment costs for both the electrolyser and fuel station itself (buffer storage, compressors, etc). Electricity costs and energy tax are the main operational costs.

In the report four different scenarios are analyzed. These scenarios and their results are presented in Table 11. Scenario 4, which is the most cost-effective scenario, where the station is assumed to constantly operate the electrolyser at as high power as possible to maximize the degree of usage. An electrolyser operated at a high capacity factor will produce more hydrogen in relation to its investment cost than an electrolyser at a lower capacity factor. With this strategy, it is also possible to use a smaller buffer storage compared to the other scenarios, thus further reducing the investment cost. The disadvantage of this scenario is that it uses less green (renewable) electricity than the other examples. In contrast to this, scenario 3, which uses only locally produced renewable electricity, turns out to be the most costly option due to the large storage required.

The main conclusions presented by the analysis are:

- Locally produced hydrogen in the current market will cost at least 14 €/kg H2
- Dedicated (off grid) hydrogen production for a fuel station is very expensive due to large storage needed.

Overall, the conclusions are similar to those in "Solar Powered Hydrogen Refuelling Stations". Both reports agree on the point that off-grid stations become particularly expensive due to the large storage volumes required.

Table 11: Scenarios in Drenthe HRS Business Case

#	Scenario Title	Description	Capex	LCOH	Green Electricity
1	Local Solar	Grid Connected with local solar panels	6.8 M€	16 €/kg H2	62 %
2	Local Solar and Wind	Grid connected with local solar panels and wind turbine	6.8 M€	16 €/kg H2	72 %
3	Only green electricity	Local solar panels and wind, no grid connection	8.8 M€	19 €/kg H2	100 %
4	High full load hours	Uses grid power only. Tries to maximize usage of cheap grid power	4.9 M€	14 €/kg H2	54 %

Aberdeen City Council – Experience and future ambitions

HyTrEc2 partner, Aberdeen City Council (ACC), is one of Europe´s pioneering cities in hydrogen technology. Since 2015,there have been fuel cell vehicles and HRS in operation in the city. Today, there are two refuelling stations with on-site hydrogen production, serving a fleet of around 80 hydrogen vehicles. There is also the ambition to further develop this with a central production hub for hydrogen, which will supply future refuelling stations.

Experience from previous projects

Growing hydrogen demand

Creating a demand for hydrogen (off-take) is recognised as an important factor for ensuring a cost-effective hydrogen supply and in trying to reach diesel price parity.

The hydrogen vehicle fleet in Aberdeen is one of Europe's largest and most varied. Along the way the ACC has encountered some challenges regarding the introduction of hydrogen vehicles. Even though certain types of FCEVs have been available for a few years, they are often still expensive to buy and not all types of vehicles are available. For example, it has been difficult to come across special-purpose vehicles such as garbage trucks. Another challenge specifically for the UK, is to get these vehicles with the steering wheel on the right hand side. For this reason, several of the hydrogen vehicles in Aberdeen's today's fleet are not fuel cell electric but rather dual-fuel retrofits of diesel vehicles with hydrogen injection (H2ICEd). These vehicles are considered as a helpful bridging technology as they are a cheaper and more accessible alternative to FCEVs, while still increasing hydrogen demand/ up-take, engendering a cultural and behavioural shift, helping with learning and training, and reducing and emissions reduction. Examples of such vehicles in Aberdeen's vehicle fleet include three roadsweepers, five waste trucks and a number of vans.

ACC has also found that as an organisation, it is not a large enough organisation to easily create a large off-take on its own; the distances within the City and mileage being undertaken by the Council's fleet doesn't require large fills. According to the study undertaken by HyTrEc2 partner, Cenex, there is the potential to create a hydrogen demand of 745 tons H2/year, and thereby create a sufficient demand across the region, by including the vehicle fleets of 12 organisations from across the northeast of Scotland. The ambition of ACC is to cooperate with other authorities in the region to introduce hydrogen vehicles to their fleets – using each others hydrogen to support vehicle deployments and each others vehicle frameworks to engender economies of scale. This includes further work with HyTrEc2 Partner, Aberdeenshire Council, which is already actively involved in operating a small fleet of hydrogen vehicles, a number secured through the HyTrEc2 project, and seeking to enlarge that capability. Aberdeenshire Council has also undertaken their own more detailed vehicle fleet study and this has evidenced that even further hydrogen demand than Cenex originally estimated is likely. The necessity for a slight overprovision to cater for future demand, given hydrogen supplies can take years to develop, likely needs to be built into the Aberdeen regional demand modelling.

The initial hope was also that other actors such as companies and private citizens would contribute towards raising hydrogen demand in the region by purchasing their own hydrogen vehicles, but so far, this has not happened. In other words, despite the presence of two refuelling stations since 2017, both of which are open to members of the public, there has not been any organic growth of the vehicle fleet yet. Presumably because of the expense and limited number of hydrogen vehicles available on the market.

Operation of refuelling stations

The two refuelling stations in Aberdeen each deliver 130 and 360 kg H2/day respectively. Hydrogen currently sells at 10 £/kg H2 at the station but this is heavily subsidised. Most of the hydrogen produced is currently used by Aberdeen's hydrogen bus fleet which consists of 15 of the world's first fuel cell electric double decker buses, and expanding to include another 10 FCEV double decker in Summer 2022

Whilst one of the stations, the one used for refuelling the buses, operates extremely well, Unfortunately, there have been a number of issues around one of the station, which has caused costs to be higher than expected. Much of the equipment in the station has been temperamental because the station has not been used to capacity; the equipment needs to be used regularly to keep the station operating efficiently and a low demand has been problematic. The equipment inside the station seems to be more well suited for even and continuous operation rather than working in intervals. It is, however, difficult to prevent these starts and stops as they are caused by regular usage of the station by few users. One way which could make starts and stops less frequent is to encourage the vehicles to only refill when the tank is close to empty. It has been found that vehicles sometimes only fill 1 – 2 kg H2 per refill, which is unnecessary. If it were possible to encourage users can be convinced to only refill when their tank is close to empty, it could be possibly reduce the wear and tear oftear in the filling station.

Another issue has been energy costs as energy efficiency was performing worse than expected. The energy costs have increased over time since the opening of the station. This is partly due to increase in electricity prices, and partly due to the degradation of the electrolysers. Frequent starts and stops seem to contribute to high energy inefficiency in the usage of the equipment, causing energy costs to be as high or higher than the sale price of hydrogen. It was reported that the calculated energy cost to switch all the equipment on at peak time and produce 1 kg of hydrogen for refilling only 1 kg H2, and that is the only refuel in the day, can be as high as £70 /kg H2. Aberdeen City Council has therefore had to ensure that the equipment only switches on during off peak periods and doesn't automatically generate hydrogen when hydrogen is dispensed.

At least one instance of equipment failure can also be attributed to user error. A retrofitted hydrogen electric vehicle drove off with the fuelling hose still attached, causing it to rip and in turn required replacement of the whole fuelling dispenser. The event however only caused damage to the equipment and no people were harmed. (It should also be noted that it is typically not possible to drive a hydrogen vehicle with the fuelling nozzle still attached but in this particular retrofitted vehicle the safety mechanism had not been implemented). This incident was further compounded by the nature of the supply chain, whereby, a technical engineer needed to visit from Belgium which was impossible for over 9 months due to Covid19 and various lockdowns in both Scotland and Belgium overlapping. Fortunately, whilst the incident sounds fairly dramatic, this did not represent any danger to the public so could be left for that period of time.

Future ambitions

The next big step for ACC is the establishment of a Aberdeen as a Hydrogen Hub, which is meant to supply further developments of refuelling stations in the region. The preferred bidder for the Hub is energy company British Petroleum [27]. The plan so far for the Hub is that it will be mostly powered by solar power from a nearby solar array but there is also the option to use grid power when solar isn't being produced and hydrogen is still required. First gas will be in 2024 with transport providing the majority of the demand. The Hub will then expand into maritime, rail and heat with the intention being to connect to offshore wind in future phases and scale up to export.

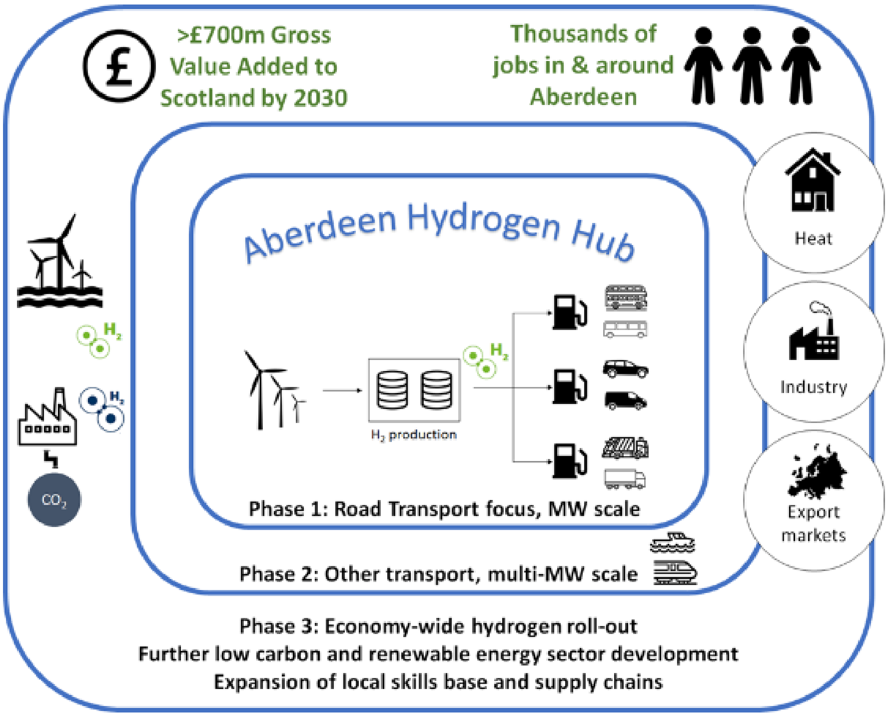

Figure 37: Graphic of Aberdeen Hydrogen Hub

Rounding off statement

From the lessons learned from the HyTrEc2 partner projects it becomes obvious that there often is a discrepancy between the economic modelling and practice.

For one it has been shown that unforeseen issues (supply chain, weather, logistics, wars, global pandemics, local resistance and more) may result in costs much higher than the costs calculated to be saved from slight efficiency improvements in economic models.

Another issue is that hydrogen as a field is yet at the start of its journey and at the moment there is little consistency in application; almost any hydrogen project being developed is as individual as the location and the circumstances it is being developed in. There is standard equipment that one can buy but the number of variables – location, input power, opportunity for nearby offtake of by-products, fluctuating levels of demand on a daily basis, nearby supply chain, etc will all ultimately influence the economics and the business case of green hydrogen production, storage and distribution that one wouldn't normally find when developing an average petrol refuelling station, for instance. It is therefore impossible to create business cases/economic models which are both highly accurate and generally applicable.

This is why the work by HyTrEc2 partners to advance hydrogen applications is critical in ensuring that real life examples can be used as lessons learned for other region's wanting to replicate a hydrogen economy.

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