REPORT

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Prizztech Oy

METHANATION PLANT – MERI-PORI

PRE-STUDY

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LIST OF ABBREVIATIONS

SNG = (Renewable) Synthetic Natural Gas
BEV = Battery Electric Vehicle
FCEV = Fuel Cell Electric Vehicle
EUA = EU Allowances (carbon credits)
EU ETS = EU Emission Trading System
AEL = Alkaline Water Electrolysis
PEM = Polymer Electrolyte Membrane Electrolysis
SOEC = Solid Oxide Electrolyser Cell
PPA = Power Purchase Agreement
GHG = Green House Gas
CCS = Carbon Capture and Storage
CCU = Carbon Capture and Utilization
HVO = Hydrotreated Vegetable Oil

1 Introduction

1.1 Background

Rejlers Finland Oy was contracted to perform a study on a potential electrolyser and methanation plant in Tahkoluoto or Kaanaa, in the Meri-Pori area.

This study is part of Prizztech Oy's "*Uusiutuvan energian investointeja Satakuntaan"* -project. The project is financed by Satakuntaliitto through EAKR-funding and the municipalities of the Pori region.

1.2 Preface, goal, and methodology

The aim of this report is to investigate the technical and economic potential of a methanation plant located in Meri-Pori.

Power-to-gas processes, in this case methane production from green hydrogen and captured carbon dioxide, has generally a high operational cost, mainly for the electricity. Crucial for the feasibility of such a plant is to have a configuration or operating model which are able to generate a positive operational cash flow. This is only possible if the so-called "refining margin" is positive. In the traditional oil & gas industry, the refining margin is the difference between the wholesale value of the oil products that a refinery produces and the value of the crude oil from which they are refined. For a power-to-gas methanation plant, the refining margin is the difference between the cost for electricity, captured carbon dioxide, and water and the sales price for synthetic natural gas, waste heat, and oxygen.

If roughly estimating this refining margin, it is quite clear that synthetic natural gas production cannot be considered profitable in Finland, as the market looks today. Therefore, the approach of this study, is not to evaluate one specific plant in detail and to conclude whether the investment is profitable or not, but to demonstrate, through sensitivity analysis, what the acceptable levelized cost of electricity could be for different values on the synthetic natural gas (SNG) and for different pay-back times. This approach will also give information on the magnitude of subsidies that may be required to initiate synthetic fuel production in Finland.

Nevertheless, even if SNG production is not profitable today, it may still be it in the future, mainly because of the political decisions. Blending obligations, production subsidies for CO_2 neutral production, and a price increase for the EU CO_2 allowances (EUAs) will improve the market for all carbon neutral alternatives. In addition, both CAPEX and OPEX is assumed to decrease for electrolysers and carbon capture technologies in the coming years. For an optimized profitability, it is also crucial that the methanation plant is part of the national frequency containment and restoration reserve market. As an increasing proportion of the power production will be from fluctuating renewable sources in the future, it can be assumed that all production plants, able to adjust their load, may somehow benefit from this development.

In order to get a correct and updated view on the available technologies in the market and the cost for these, RFQs (Request for Quotation) have been sent out to different providers of electrolysers and methanation reactors, as a part of this project. The idea of these requests is not to make a traditional vendor comparison, but to screen the available technologies in the market, and by that be able to propose a plant configuration or operational model which currently is the best alternative for this location. The profitability analysis in the end of this report will be based on this configuration.

2 Technology options

2.1 Electrolyser

In this chapter the three most common electrolyser technologies are presented and compared. The final choice of electrolyser technology is in the end depending on the site-specific needs.

2.1.1 Alkaline Water Electrolysis (AEL)

Alkaline water electrolysis (AEL) is the oldest, simplest, and most time-tested technology. It is also characterized by relatively low capital costs compared to other electrolyser technologies due to the avoidance of precious materials. Most of large scale commercially running plants today are based on AEL. The working principle is simple. When a direct current is applied to the water, containing an alkaline chemical catalyst, usually 25% potassium oxide, the water molecule is split into oxygen and hydrogen. The alkaline electrolyte let the ions be transported between the electrodes. AEL electrolysers are operating close to atmospheric pressure and at temperatures between 60 and 90 °C.

Common suppliers of AEL technology are:

- Thyssen Krupp, Germany
- NEL hydrogen, Norway
- Sunfire, Germany

The drawbacks of AEL is that the ramp-up and ramp-down time from maximum to minimum is about 10 minutes. However, for example Thyssen Krupp are nowadays promising 30 seconds in the normal operational range (10-100%) within 30 seconds, so AEL shouldn't automatically be excluded, even if looking for a system which, able to work as a frequency containment reserve for disturbances. Moreover, as todays battery technologies are improving, hybrid solution could be considered, to improve the response time for AELs.

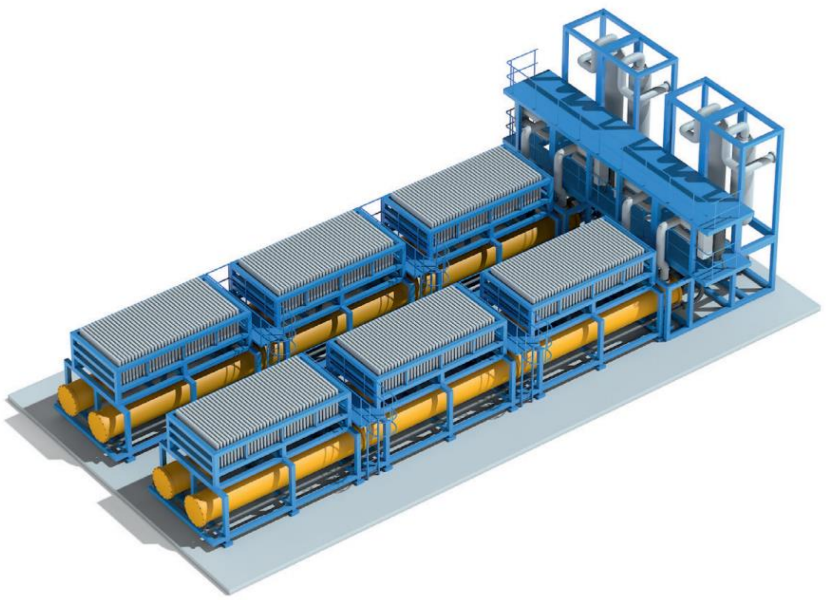

Figure 1. AEL example, Thyssen Krupp 20 MW electrolyser unit. (Thyssen Krupp 2021)

2.1.2 Polymer Electrolyte Membrane (PEM)

PEM electrolysers use pure water as an electrolyte solution, meaning that no recovery and recycling of the potassium hydroxide electrolyte solution is necessary. Their footprint is also smaller compared to AEL installations, making them more attractive in dense areas. They are also operating at higher pressures than AEL which means that additional and expensive compressors could usually be avoided. PEM is ideal for flexible operation which make them suitable for different frequency containment and restoration reserve applications.

Nevertheless, the drawback with PEM is the need of expensive electrode catalysts (platinum, iridium) and membrane materials. Their lifetime is currently also shorter than that of AELs. So, in the end, AEL is often the most reasonable alternative for many sites, when looking in to the overall profitability. However, the cost difference between AEL and PEM are decreasing all the time, and will probably continue to decrease even further in the future.

Figure 2. PEM example, Hydrogenics (Cummins) 5 MW unit. (Cummins 2021)

Common suppliers of PEM technology are:

- Siemens, Germany
- MAN Energy Solutions (H-Tec Systems), Germany
- Cummins (Hydrogenics), USA

2.1.3 Solid Oxide Electrolysis Cell (SOEC)

SOEC is the least developed electrolysis technology and is not actually even completely commercialized yet, although many companies are now aiming to bring them to market. SOECs may play a crucial role in the future low carbon economy. As both Alkaline and PEM electrolysis use an electric current to split the water molecules, the SOEC technology is a combination of using electric energy and heat. It is advantageous to use heat as the primary energy source, as it is generally less expensive to store than electric power. One operational model could for example be to produce hydrogen at basically constant rate, but to produce and store the heat, required for the process, only when surplus or cheap energy is available.

SOECs operate at very high temperatures around 700-900°C. High temperature operation results in higher electrical efficiencies than for AEL and PEM, but the drawback is that it has challenges in material stability.

Another potential advantage of SOECs is the ability to not only produce hydrogen, but a mixture of hydrogen and carbon monoxide, by adding carbon dioxide to the unit. This means that SOECs can be thermally integrated with a range of different chemical synthesis, enabling for example SNG production with improved efficiency compared to current production technologies.

As said, SOEC is an immature technology so there are not many commercial alternatives available yet. Neste Oy has currently acquired a part of the German company Sunfire, which are focusing on SOEC technology. Haldor Topsoe are currently investing in a manufacturing site for commercial SOEC electrolyser systems. The manufacturing site will be in operation in 2023 and the said efficiency for these electrolysers is > 90%. However, it is still a little bit too early to consider SOEC as a viable alternative for this study.

Figure 3. SOEC example, Haldor Topsoe, SOEC prototype stack. (Haldor Topsoe 2021)

2.1.4 Choice of electrolyser technology

The profitability analysis of this study will be based on AEL technology. The main reason is the cost, which is usually about 50-60% of the cost of PEM technology. The advantage of PEM is its ability to handle changes in loads more rapidly as well as their decreased foot-print. However, this is still, as the market looks today, outcompeted with the fact that AELs has a significantly lower investment cost.

2.2 Methanation unit

In a methanation reactor, synthetic methane is produced by reacting carbon dioxide and hydrogen in a Sabatier reaction. There are two main alternatives in how the reaction can be catalyzed: either at high temperatures and pressure in a conventional methanation reactor with a metal catalyst or in a biological reactor at lower temperature and atmospheric pressure.

The two alternatives are discussed and compared in this chapter.

2.2.1 Conventional methanation

Conventional methanation of carbon dioxide and hydrogen is a catalytic reaction, which takes place at temperatures between 200 to 500°C. The reaction is exothermic which means that it produces heat, which has to be removed from the reactor.

A standard solution is to use a nickel catalyst at a temperature of about 400°C and a pressure at 10-20 bar. Reactor cooling is essential, as overheating of the reactor will destroy the catalyst. This is typically done with a water-steam circuit, which uses the heat to boil water. This is also beneficial for many applications, as the heat can then be utilized in other applications as high-pressure steam.

The reactor temperature can also be controlled by re-circulating part of the product stream and thus affecting the rate of the reaction. A tailor-made design is usually possible for the methanation reactor, if certain pressure levels are required for the steam and/or the methane.

Common suppliers of conventional (or chemical) methanation technologies:

- MAN Energy Solutions, Germany
- Inova (Hitachi Zosen), Switzerland/Japan
- Haldor Topsoe, Norway

2.2.2 Bio-methanation

Bio-methanation is a similar type of conversion, but instead of a metal catalyst, methane is formed as a result of microbiological activity. Bio-methanation is also called methanogenesis. The reaction occurs at significantly lower temperatures than in a conventional reactor. The pressure is also lower, typically 1 bar(a). This is an advantage as no compressor power is needed to increase the pressure of the hydrogen and the CO_2. However, a SNG compressor may instead be needed after the reactor, to reach the required pressure in for example the natural gas pipeline. Another advantage of bio-methanation is that the microbes are bio-origin and not toxic, which is the case for standard nickel catalysts, classified as a carcinogenic.

Both of the main methanation technologies are sensitive to oxygen and other impurities in the feed gases. However, biological methanation plants seem to be more resistant to oxygen. This could be a crucial factor, as reaching low O_2-concentration in feed gases may require more complex, and therefore more expensive technology.

The greatest benefit for bio-methanation is that the reactor can be used for biogas upgrading. In this case the biogas is fed straight to the biological reactor, and the excess of CO_2 is reacting with the hydrogen. The biomethane in the stream is just an inert component. The advantage of this process is that no CO_2 capturing or separation is required, as the stream can be fed straight to the reactor. This will both save energy (OPEX) and reduce the investment cost (CAPEX).

Common suppliers of bio-methanation technologies:

- Q Power, Finland
- Electrochaea, Germany
- microbEnergy, Germany

2.3 Choice of methanation technology

The profitability analysis in this study will be based on conventional methanation technology. These reactors have a lower investment cost and are also more time-tested. Even if the overall efficiency of these reactors may be slightly lower than for a bio-methanation unit, the cooling streams are much more valuable and can easier be traded and utilized in waste heat recovery applications to a higher price. As the cooling of bio-methanation reactors happens at around 50°C, heat pumps are more or less always required to utilize this heat, which is increasing the difference in investment costs even more. However, a fair and detailed vendor comparison should always be carried out, before making final investment decisions.

3 Plant products and their market environment in the Meri-Pori area

In this section the market environment for hydrogen, synthetic natural gas, waste heat, and oxygen are briefly discussed, from a Meri-Pori perspective.

3.1 Hydrogen

As there is currently no large hydrogen consumer in the Meri-Pori area, production of it, without further processing into for example synthetic natural gas, would not be sensible. Hydrogen is very different from other industrial gases, as its compression, storage, and transportation are very expensive and energy consuming. This means, that for *large-scale* users, it is better to have on-site production, than to have the hydrogen transported to the site in tank trucks. The price in Finland for industrial hydrogen, produced on-site in steam-reforming units, is about 3 times the price for natural gas, in other words **80-120 €/MWh**. However, there are large site-specific variations. Usually the price is also linked to the price of European CO_2 allowances, which is currently increasing rapidly.

To *small-scale* users, compressed hydrogen is however delivered by road transportation, but in these cases, the business driver and competitiveness is not the actual hydrogen production, but the logistics and the distribution. Moreover, as it concerns small amounts, it would require a very broad customer base to cover the complete demand of a large electrolyser plant.

In theory, centralized production and distribution to *medium-scale* consumers by road transportation, for example hydrogen filling stations for the heavy transport sector, could be a feasible concept. However, the problem in Finland is that the use of hydrogen, outside the industrial sector, is more or less non-existent. There are for example no hydrogen cars, no hydrogen buses, no hydrogen trains, and a very limited number of fuel cell fork trucks.

This is thus a real chicken-and-egg strategy problem. Even if it can be assumed that BEVs (Battery Electric Vehicle) may be dominating at least the passenger car market in the future, there may be a demand for also hydrogen fueled FCEVs (Fuel Cell Electric Vehicle), at least for the heavy transportation sector. The current price for gasoline and diesel in Finland is actually comparable to a hydrogen price of **250 €/MWh**, considering that no excise tax has to be paid for the hydrogen and that the FCEVs has a better total efficiency and therefore also lower consumption. At this price level, green hydrogen production could be considered profitable, even if a significant part of the sales price has to cover the cost for pressurizing and distribution. However, the problem is that FCEVs makes no sense, if there are only a small fleet of them. There has to be a sufficient number of filling station to cover at least the most populated areas in Finland. Also, the distance between the stations and the production site should be as short as possible. Moreover, the size of the hydrogen plant should preferably be at least 10 MW, in order to keep the specific investment cost down. This would require a customer base of 8 000 passenger cars or 250 busses. Basically, this mean that if the use of hydrogen in the transportation sector will take-off in Finland in the coming years, the hydrogen has to come from a production plant, which are also providing hydrogen for a large-scale industrial customer. Alternatively, part of the hydrogen could be used for synthetic fuel production. Otherwise, it will not be possible to build hydrogen production plants of a sensible size. However, there is one exclusion. If the electrolyser size is below 1 MW, the plant can be containerized, meaning that the size specific investment cost for really small plants is not necessarily unreasonably high. In other words, one feasible concept for tanking stations in the future could also be to have on-site production, with small 1 MW containerized electrolysers.

Nevertheless, when evaluating the hydrogen potential in Meri-Pori according to the current market environment and outlook, it is clear that the sales of hydrogen cannot really be considered in the profitability analysis in this study. The future is uncertain and there is no simple solution to the chicken-and-egg strategy problem related to the use of hydrogen. However, if the market outside the industrial sector will start to take-off soon, a methanation plant can always be used for also hydrogen production exclusively, without methanation.

3.2 Synthetic Natural Gas (SNG)

The situation for SNG is completely different than for hydrogen, as both the infrastructure (Gasum LNG terminal) and the demand for this is already available in the Meri-Pori region. As the current government's climate policy states that Finland should be carbon neutral by 2035, there are a significant market potential for carbon neutral alternatives to fossil natural gas, such as biogas and SNG, at least for an extensive transition time. Even if for example the full biogas potential would be utilized in Finland, it will not be enough to cover the current demand of fossil natural gas.

However, the challenges with SNG is that its production is very expensive. Even if electricity is the largest operational cost, the need for balancing power and frequency containment/restoration reserves may increase in the future, making Power-to-Gas projects generally more profitable and justified. Therefore, the biggest challenge for SNG production, from a fundamental point of view, is the availability of concentrated sources of CO_2 and accordingly also the cost for it. Direct air capturing (DAC) is of course always an alternative, but with today's technology, the energy consumption for extracting 1 tons of CO_2 from the air is about 1.6-2.6 MWh. So, in other words, the CO_2 availability of the SNG production may in the future be the limiting factor, and therefore the future market could be smaller than often anticipated.

There are currently no commercialized (renewable) SNG production in Finland, but it can be assumed that the market for SNG is basically identical to the market for biogas. Currently the best market for biogas is for road transportation. For example, Gasum's current price is between 1.43 and 1.48 €/kg (VAT 24%) at the station. This corresponds to about **84 €/MWh** (VAT 0%). However, this price includes transfer fees and transportation cost, as well as sales margin, so the product price from a producer point of view is naturally lower.

In several reports, it is said that synthetic methane production would be profitable for prices around **150 €/MWh**. With effective by-product utilization, a lower price can be accepted, about **125 €/MWh.** A price of 150 €/MWh may sound unreasonably high, but as a transportation fuel, it is basically comparable to a gasoline price of 1.7 €/l for the consumer, so with blending obligations and an increase in the excise tax, this price could be realistic, considered that the SNG will be excise duty-free, like the current situation for biogas. However, the competition from BEVs should always be considered.

Still, even if a price of 150 €/MWh could be feasible for road transportation in Finland, it will not be it for the shipping industry, which today pays around 30 €/MWh for the LNG, depending on the logistics. So, in this case, either the shipping companies or the SNG producers need to get operating subsidies, as the shipping companies otherwise have no chance to survive if the market prices are pushed to 125-150 €/MWh through political decisions and extensive blending obligations. Therefore, it is likely that synthetic methane production will require a guaranteed price system (feed-in tariff), likewise the one adopted for wind, biogas, and wood-based fuel power stations in Finland 2011. Otherwise, this will probably not be a realistic option.

3.3 Waste heat

Production of hydrogen and synthetic fuels is also producing large amount of waste heat. The utilization of this heat will improve the profitability of the plant significantly. One way to see it would actually be to consider a methanation plant as a production unit of both SNG and heat, not only SNG.

Depending on the chosen technology for electrolysis and methanation, the temperature distribution and mass flows of the waste heat streams are varying. For some applications, part of the heat is low-temperature, as low as 40 °C. However, as long as there are suitable consumers available, it can be assumed that utilization of all heat, with for example heat pumps, is profitable. One reason is that a SNG should always, to some degree, be optimized against the electrical spot price. This means that the heat pumps will not be operated when the cost for electricity is very high.

In the table below, the Helen Oy's purchase price for waste heat, that can be utilized for district heating is presented:

Table 1. Example of district heating purchasing prices, Helen Oy 2021.

Kausi	Ajanjakso	Ostohinta €/MWh, alv 0 %	Hintakerroin kaukolämmön energiamaksusta
Kevät	**1.3.-30.4.2021**	**28,61**	**50 %**
Talvi	1.1.-28.2.2021	37,95	70 %
Syksy	1.10.-31.12.2020	28,22	55 %
Kesä	1.5.-30.9.2020	11,25	40 %

The temperature requirement for the heat in the table above is only 80°C. However, this is only an example of market prices but doesn't reflect the actual situation in the Meri-Pori area. In this region Porin Energia is responsible for the district heating network and project specific purchase price needs to be agreed separately.

3.4 Oxygen

The electrolyser is producing large amounts of pure oxygen. It could for example be mentioned that an installed electrolyser capacity of 1700 MW would be enough the cover the whole demand in Finland, about 1.3 Mt annually.

The most profitable end-use for electrolyser by-product oxygen is a direct connection to medium-scale users which currently receive their oxygen in liquid form by tank trucks. In these applications, the cost for oxygen is relatively high, due to the transportation, meaning that the value obtained for electrolyser oxygen through a direct connection would also be higher.

Another potential market for the electrolyser oxygen would be a direct connection to a large-scale industry user, which typically receive oxygen from on-site generation systems, operated by an external company, specialized in industrial gases. In this case the variable production cost for this oxygen is about **15-20 €/tO_2**, including margins from the oxygen provider.

However, in the Meri-Pori area, there are currently no industrial users of significant amounts of oxygen. Therefore, there are only two alternatives for the oxygen; either to liquefy it and transport it to small- or medium-scale users or to dissipate it into the air.

In principle, liquefaction and distribution of electrolyser by-product oxygen is not identified as a potential business case for a synthetic fuel producer. The reasons are as follows:

- The competitive advantage of selling oxygen to small- and medium scale users is primarily the optimization of the logistic chain, not the separation of the actual oxygen, which is a fairly simple and cheap process.

- Electrolyser oxygen is not a totally “free” by-product. Drying, capturing and liquefying of the oxygen will increase the capital expenditure of the plant.

In other words; even if utilization of electrolyser by-product oxygen has a significant contribution to the overall profitability of an electrolyser plant, the added value from this operation is negligible, if no consumer is available at a close distance.

4 Consumables and their cost structure

4.1 Electricity

Electricity stands for about 60% of the operational expenditures in a methanation plant. Therefore, the cost for electricity is also absolutely crucial for the overall profitability.

4.1.1 EU Regulations

There are some limitations on how the power purchasing should be arranged in order to have the right to classify the SNG as fully renewable. The following text is taken from the EU RED II directive:

"Renewable liquid and gaseous transport fuels of non-biological origin are important to increase the share of renewable energy in sectors that are expected to rely on liquid fuels in the long term. To ensure that renewable fuels of non-biological origin contribute to greenhouse gas reduction, the electricity used for the fuel production should be of renewable origin. The Commission should develop, by means of delegated acts, a reliable Union methodology to be applied where such electricity is taken from the grid. That methodology should ensure that there is a temporal and geographical correlation between the electricity production unit with which the producer has a bilateral renewables power purchase agreement and the fuel production. For example, renewable fuels of non-biological origin cannot be counted as fully renewable if they are produced when the contracted renewable generation unit is not generating electricity. Another example is the case of electricity grid congestion, where fuels can be counted as fully renewable only when both the electricity generation and the fuel production plants 21.12.2018 EN Official Journal of the European Union L 328/95 are located on the same side in respect of the congestion. Furthermore, there should be an element of additionality, meaning that the fuel producer is adding to the renewable deployment or to the financing of renewable energy."

In other words; The electricity used for the electrolyser should be produced simultaneously as the hydrogen for the methanation reactor is produced. Moreover, no grid congestions are allowed between the power production unit and the electrolyser. Further, there are some requirements on additionality for the power production, meaning that only new-build and (partly) dedicated power production units may be accepted for green hydrogen production.

However, the text above leaves several question marks. How is for example grid congestion defined and what does additionality mean in practice? These issues are currently under discussion in the European Commission, and a delegated act regarding synthetic fuels / electro fuels is promised in the end of 2021. Nevertheless, the Meri-Pori area is in many perspectives ideal for synthetic fuel production, meaning that regardless of what the decisions are, the plant can be configured in such way that it complies with the delegated act for synthetic fuels.

4.1.2 Cost structure

Normally, the power purchasing for an industrial plant consists of the following components:

- Power spot price (SYS+EPAD)
- Transfer fees (110 kV)
- Taxation
- Other costs, such as physical delivery fee, guarantees of green origin, balancing power trade costs, Fingrid-fee and balance service costs.

The sum of these components is total cost for electricity. However, in this case, the total cost can be reduced in many ways, as the plant will possible be integrated with Suomen Höytytuuli Oy's wind farm. This will be discussed in the coming chapters.

4.1.3 Power spot price (SYS+EPAD)

One of the fundamental ideas of power-to-X or power-to-gas projects, is the ability to utilize surplus electricity for production of other energy sources and by that contribute to balancing the supply and demand of the electricity market. Therefore, spot price optimization should always be a central part of the operation. Even if it is possible to make different fixed Power Purchase Agreements (PPAs), the spot price should always be seen as the *alternative* cost for electricity.

For each plant, a so-called breakeven price for electricity can be calculated. The breakeven price is the total electrical price that can be allowed in order to avoid a negative impact on the pay-back time. It is based on the sales price of the product streams and the variable costs for the consumables and thus linked to the earlier discussed refining margin. It should be noted that even if the total electricity price stays below the breakeven price, it doesn't automatically mean that the business as such would be profitable, as there are also fixed operational costs, which should be considered as well as requirements on the pay-back time. Basically, the breakeven price only provides information on at which price the electrolyser should be put on standby. The levelized electrical price thus has to be lower than the breakeven price, to have a profitable business.

A high price on the products will lead to a higher breakeven price and thus more running hours for the plant, while a low value on the products will lead to a low breakeven price and fewer operating hours.

One example of spot optimization is presented below:

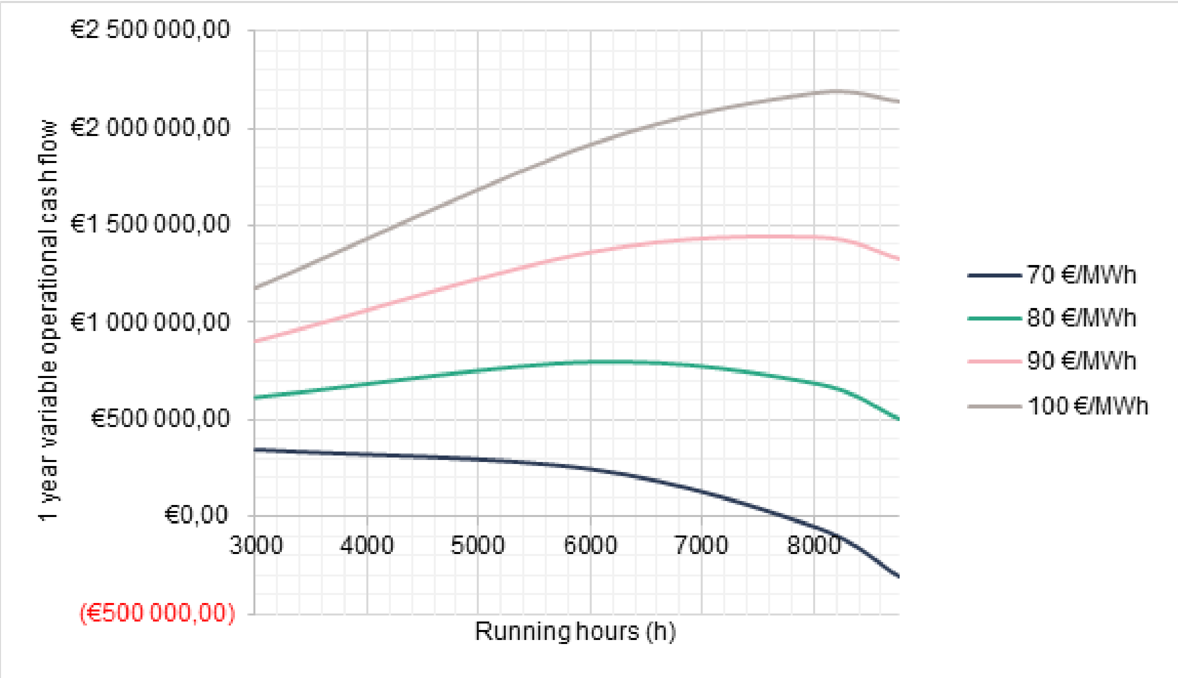

Figure 4. Example of the relevance of spot-optimization. 1-year cash flow for different SNG sales prices and plant running hours.

The figure presents how the variable operational cash flow is affected by the running hours for different sales price on the SNG. With a SNG price of for example 80 €/MWh, the plant should be in operation only during the cheapest 6000 hours, while with a price of 100 €/MWh, the plant should be kept in operation more than 8000 hours, meaning that the electrolyser would be on stand-by only when the electricity price is actually very high.

The spot price distribution used in the figure is a future estimate, based on the historical prices for the Nord Pool. The purpose of the figure is only to generally demonstrate spot-price optimization, plant specific sensitivity analysis will be carried out later in this report and presented in chapter 6.

As mentioned in chapter 4.2, there may be requirements stating that the methanation plant is only allowed to be in operation when the dedicated production unit is in production. This means that spot-optimization for all 8760 hours in a year will not be possible, as wind turbines are always off-line during certain conditions, normally about 10% of the time. Part of the spot-optimization will thus occur spontaneously, if considering a so-called “as-produced” operating model.

4.1.4 Transfer fees (110 kV)

As there in this case may be possible to have a direct connection to Suomen Hyötytuuli Oy’s wind farm, transfer fees can possible be avoided. This is depending on the final location of the plant. If transfer fees can be avoided, it may decrease the total cost of electricity by about **5.00 €/MWh** in average, which is about 800 000 € annually.

It should be noted that transfer fees can never be avoided or decreased by making individual deals with the grid provider, that is prohibited by the electricity market act. The price level has to be equal for all consumer connected to the same grid system.

4.1.5 Taxation (LK2 for this installation)

As there are currently no commercial power-to-gas plants in Finland, it is unclear whether electricity tax is required for the plant if it is directly connected / integrated with the Tahkoluoto wind power station.

4.1.6 Other costs

Many of the external costs that industrial plants generally have to pay related to the power purchasing can be avoided, if the methanation plant is closely integrated with Suomen Höytytuuli Oy’s operations. These are for example physical delivery fee and costs for balance services. The plant can also be seen as an instrument in the power balance trading, as it can for example be shut-down, if required.

4.1.7 Frequency containment and restoration

By participating in the frequency containment and restoration reserve market, the total cost for electricity could possibly be decreased. In the Hydrogen Roadmap for Finland (Business Finland 2020) it has been estimated that the income from the *frequency containment reserve for disturbances* (FCR-D) and *automatic frequency restoration reserve* (aFRR) market could cut the total electricity cost with about 15%, for an electrolyser installation. However, this has to be evaluated in detail when more information on the future running profile for the plant is available.

In the profitability analysis later in this report, the power purchasing components will not be mentioned separately, but the cost for electricity will be given as a levelized lump sum for certain operation hours per year. This cost is assumed to include all aspects of power purchasing, even the potential income from the frequency containment and restoration reserve market.

4.2 Carbon Dioxide, CO_2

A methanation plant roughly consumes 0.2 t/CO_2 per MW produced SNG. In this study, CO_2 is assumed to be purchased as a raw material, so no capturing equipment is included in the capital expenditures for the methanation plant.

To evaluate a realistic purchase price for the CO_2, the cost for capturing should also be understood. CO_2 separation from a gas mixture is an energy intensive process, and from an economical point of view, the most important factor is the initial concentration of CO_2 in the stream, as the theoretical minimum work for CO_2 separation increases strongly when the concentration of CO_2 in the raw gas stream decreases. This is shown in the figure on the next page:

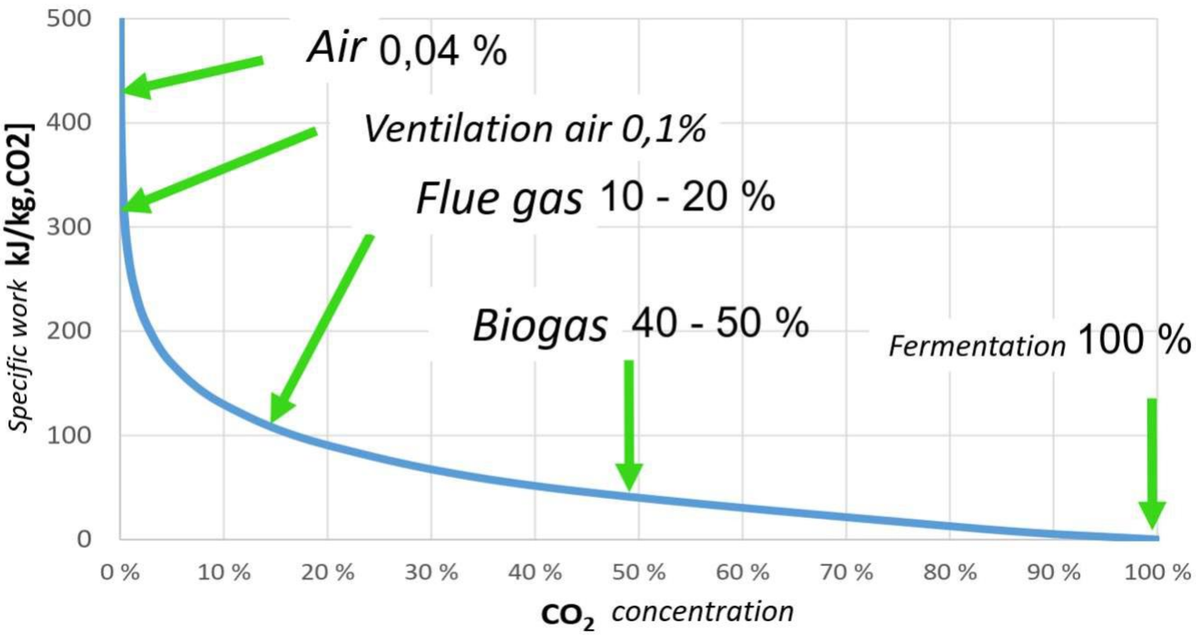

Figure 5. Theoretical minimum work of CO_2 separation as a function of initial CO_2 stream and several CO_2 concentrations of various gas streams (Hiilidioksidin talteenotto ilmakehästä, Tero Tynjälä, LUT, 2019).

Moreover, low CO_2 concentration means that a higher volume of raw gas stream must be treated and the equipment size, as well as investment costs, are increased.

Below a few examples on CO_2 capturing costs:

- Side stream of ethanol fermentation is almost pure CO_2 and requires only compression. The total cost is roughly **10 €/t CO_2**.

- Cement production contains side streams with high CO_2 concentration. The capture cost is about **70 €/t CO_2**.

- Current benchmark cost for CO_2 separation from flue gases is roughly **100 €/t.**

- Experience from existing demonstration plants shows that the cost for captured CO_2 could be decreased in the future. For example, the captured cost for a 2nd generation large-scale plant (2Mt CO_2/a), is estimated to be only **45 €/t CO_2**.

In this project there are several options for CO_2 purchasing:

1. BioEnergo, Kaanaa.
2. Aittaluoto and/or Kaanaa power plants, new CC-unit.
3. Other suppliers, synergies with Critical Metals' vanadium recovery and production project.

BioEnergo's future ethanol plant in Kaanaa, will produce CO_2 as a byproduct from the fermentation and possible also from the biogas. The actual cost for this production/capturing is comparably very low, but that doesn't automatically mean that the CO_2 would be sold to a reduced price. Also, the market development and general demand has to be taken into consideration when evaluating the purchase cost.

Therefore, as a base for this study, a purchase price of **100 €/tCO_2** will be used. This may also be a realistic price in the future, if carbon dioxide is captured from the Aittaluoto or Kaanaa power plants. However, in the sensitivity analysis the range will be between **0 and 200 €/tCO_2**. Carbon dioxide as such will never be totally for free, but the 0 €/t case, represents a situation in where the methanation plant is used for biogas upgrading, as described in chapter 2.2.2. In this case the biogas stream containing CO_2 is fed straight into the methanation reactor, i.e., no separate carbon capturing is required.

A price of 200 €/tCO_2 may sound unreasonably high, but it cannot be excluded. If synthetic fuel production really takes-off, the demand for CO_2 will increase. Moreover, the availability of concentrated CO_2 sources may decrease, as the number of EUAs will decrease. A common misunderstanding is, that the EUAs could be traded, if the CO_2 is captured and sold for synthetic fuel production, but that is not the case. If systematically looking into the mass flows of the CO_2 capturing process, the methanation, and the end use, it is clear that the EUAs cannot be traded, as the captured CO_2 molecule will still end up in the atmosphere.

However, it has to be said that in the end it is a political decision of how GHG emissions are to be calculated. At the moment there are actually no clear regulation on carbon capture and utilization (CCU) in synthetic fuel production but it will probably be covered in the delegated acts for regarding these, which is said to be issued by the European Commission later this year.

Nevertheless, it would be surprising if fossil carbon capturing will allow for EUA trading, regardless of where the CO_2 will be utilized, as that would mean double-counting in emission reduction for certain applications, which is against the principles of the EU emission trading system.

So, all in all, there are several project risks related to the availability of CO_2 and its market price. One way to eliminate this risk would be to consider "so-called" closed loop systems, where all CO_2 will be captured from the same industry which uses the SNG. However, as the market looks today, the primary use for SNG would be transportation, not industrial applications, as transportation fuel prices are generally much higher than industrial fuel prices, mainly because of the tax policy.

4.3 Water

An electrolyser consumes about 1 liter per Nm^3 produced H_2. For a 20 MW installation, it means about 4000 m^3/h. The conductivity requirements are usually around 5 µS/cm, meaning that water treatment equipment is needed, even if potable water is used.

In Finland there are generally a good infrastructure for potable water in industrial areas, so this will not be analyzed in detail in this study. However, the operational cost for water is naturally considered in chapter 6, profitability analysis.

5 Technical plant configuration, size, and location

5.1 Size

At first, when discussing power-to-gas plants, the size is always referring to the power supply to the plant, not the gas production. As an example; a 20 MW methanation plant with an overall efficiency of 50%, has a methane production of 10 MW.

The size is crucial for the overall profitability. The investment cost, in EUR per MW installed capacity, is heavily increasing when the installed capacity goes below 10 MW. Therefore, a new installation should be targeted to an area, where it is sensible to build a 10+ MW plant. Really small plants, below 1 MW, may also have a reasonable investment cost, as they can be delivered as containerized solutions. However, in this study, this solution is not of interest.

As the fundamental idea of power-to-gas plants is basically to “refine electricity”, it is important to be able to eliminate all extra costs related to the power purchasing. A power-to-gas plant should preferably be built with a direct connection to a source of renewable electricity, in order to avoid transfer fees and other grid costs. However, this is not always possible. Generally, the capacity specific transfer cost for a 110kV connection is lower than for a 20kV connection. However, to make a 110kV connection for smaller methanation plant, if for example 20kV would be available at close distance, is not sensible, as it would mean a disproportionately high investment cost. This is thus another example of why large plants generally has a better overall profitability.

Nevertheless, even if “bigger is generally better”, there naturally also has to be a demand for the products and all required consumables, for example CO_2, should be available. By taking this into consideration, the conclusion is that the recommended size in this study will be about 20 MW, as this is still a completely feasible concept for the Meri-Pori region.

5.2 Locations

There are currently two different alternatives for the methanation plant in Meri-Pori; Tahkoluoto and Kaanaa. The advantages and disadvantages of these will be discussed in this chapter.

5.2.1 Location 1: Tahkoluoto

The basic idea with the Tahkoluoto location is the that it is close to Hyötytuuli Oy’s wind farm, making it possible to have a direct connection to the production units and by that avoiding transfer fees for the electricity. Moreover, it is close to Gasum Oy’s LNG terminal, meaning that there may be some synergies regarding the infrastructure for distribution of SNG.

The main disadvantage of this location is that heat cannot be utilized to its full potential. There is a smaller district heating network in Reposaari but this is not enough to cover the complete heat production by this plant. Moreover, it will also require a new transfer pipe of about 2 km, which will increase the total investment cost. Another disadvantage of locating the plant in Tahkoluoto, is that the CO_2 has to be transported to the site by tank trucks, if purchased from BioEnergo’s plant. However, it is possible that there will be a CO_2 storage in the Tahkoluoto area in the future, as a part of the Critical Metals’ vanadium recovery and production plant.

A methanation plant of this size require a plot of about 5000 m². In the figure on the next page, one alternative plot for the methanation plant in Tahkoluoto is indicated with blue. It should be noted that no discussion with the landowners has been carried out as a part of this study.

Figure 6. Methanation plant location alternative in Tahkoluoto.

5.2.2 Location 2: Kaanaa

By locating the methanation plant in Kaanaa, it would be possible to make a straight connection to BioEnergo's carbon capturing unit, and by that avoid expenses for CO_2 road transportation. In this location, utilization of all the heat produced by the plant is possible, at least in theory, as the district heating network in this location is larger. It may also be possible to find some synergies regarding SNG distribution, as BioEnergo's future plant will also produce biogas.

The biggest disadvantages of locating the plant in Kaanaa is that transfer fees for the 110kV electricity supply has to be paid to Porin Energia. This will have a negative effect on the operational cash flow of about 800 000 € annually.

In the figure on the next page, one alternative plot for the methanation plant in Kaanaa is indicated with blue. As for also the Tahkoluoto case, no discussion with the landowners has been carried out as a part of this study.

Figure 7. Methanation plant location alternative in Kaanaa.

5.3 Technical configuration

The core of the proposed plant configuration is an atmospheric alkaline water electrolyser with a hydrogen production capacity of 3880 Nm³/h or 8.3 t/day. The electrolyser system consists of eight electrolyser stacks in parallel.

High voltage AC (110 kV) power is supplied to two transformers that lower the voltage and feed four rectifiers that in turn supply the needed DC current for the electrolysis reactions:

Cathode:	$2H_2O + 2e^- \rightarrow H_2 + 2OH^-$
Anode:	$2OH^- \rightarrow \frac{1}{2}O_2 + H_2O + 2e^-$
Total:	$2H_2O \rightarrow O_2 + 2H_2$

The alkaline used is a 25% aqueous solution of potassium hydroxide (KOH), also called lye. Lye is not consumed in the reactions, but refilling is required after for example maintenance activities.

The product gases from the electrolyser stack are fed to their own gas/liquid separators to recover lye from the product stream. Each stack has two separator vessels, one for the oxygen and one for the hydrogen.

After separation, the hydrogen gas is lead to a common hydrogen gas scrubber, which cools the gas and removes residual lye. After the scrubber, the hydrogen is pressurized to about 10 bar(g) in two hydrogen compressors and further fed to the deoxidizing system, to remove oxygen and to reach the purity requirements of the methanation reactor.

Because the gas streams are saturated with water from the electrolysis onwards, and the streams are cooled along the process, water continuously condenses. Some is collected in the scrubbers and returned to the process, and the rest is drained in several places. In the end of the electrolyser process, the hydrogen is dried to final specification in dryers. To absorb water, they contain a desiccant, which periodically needs to be regenerated.

After drying, the hydrogen stream is preheated and mixed with CO_2, before it enters the methanation reactor. The methanation reactor consists of two zones: the catalyst zone and the cooling zone. In the catalyst bed, methane is formed by the following equilibrium:

$$\mathrm{CO_2} + 4\,\mathrm{H_2} \rightarrow \mathrm{CH_4} + 2\,\mathrm{H_2O}$$

In the cooling zone, the heat released by the exothermic reaction is removed and steam is produced. Normal operation temperature of the steam drum is about 250°C. From the steam drum, steam is released by pressure control and water make up done by level control. The water is circulating through the reactor by natural draft. Driving force is thus the difference in density of water/steam compared to the one of subcooled water.

After the cooling zone, the product gas is further cooled in a chiller to about 10°C. Condensate is separated from the product gas stream and degassed before it is fed to the gas upgrading unit and further to the local gas grid at a pressure of about 5-8 bar(g). Methane content of the gas is about 96%.

In the table below, the streams of this plant configuration are listed:

Table 2. Streams of the proposed technical configuration.

Consumables			
Description	***Amount***	***Unit***	***Notes***
Electrolyser water	4.6	m3/h	5 µS/cm
Electricity	18.9	MW	110 kV
Carbon Dioxide	1.86	t/h	

Products			
Description	***Amount***	***Unit***	***Notes***
Synthetic Natural Gas	9.32	MW	5 bar(g), methane content 96%
Oxygen	2.98	t/h	Vented to the atmosphere

Cooling			
Description	***Amount***	***Unit***	***Notes***
Stack cooling	3.66	MW	70/40 °C (in/out)
Compressor cooling	2.70	MW	40/20 °C (in/out)
Reactor cooling	1.22	MW	25 bar(g)
Condense	0.20	MW	110 °C, no return to system

In the figure below, the general technical configuration is shown:

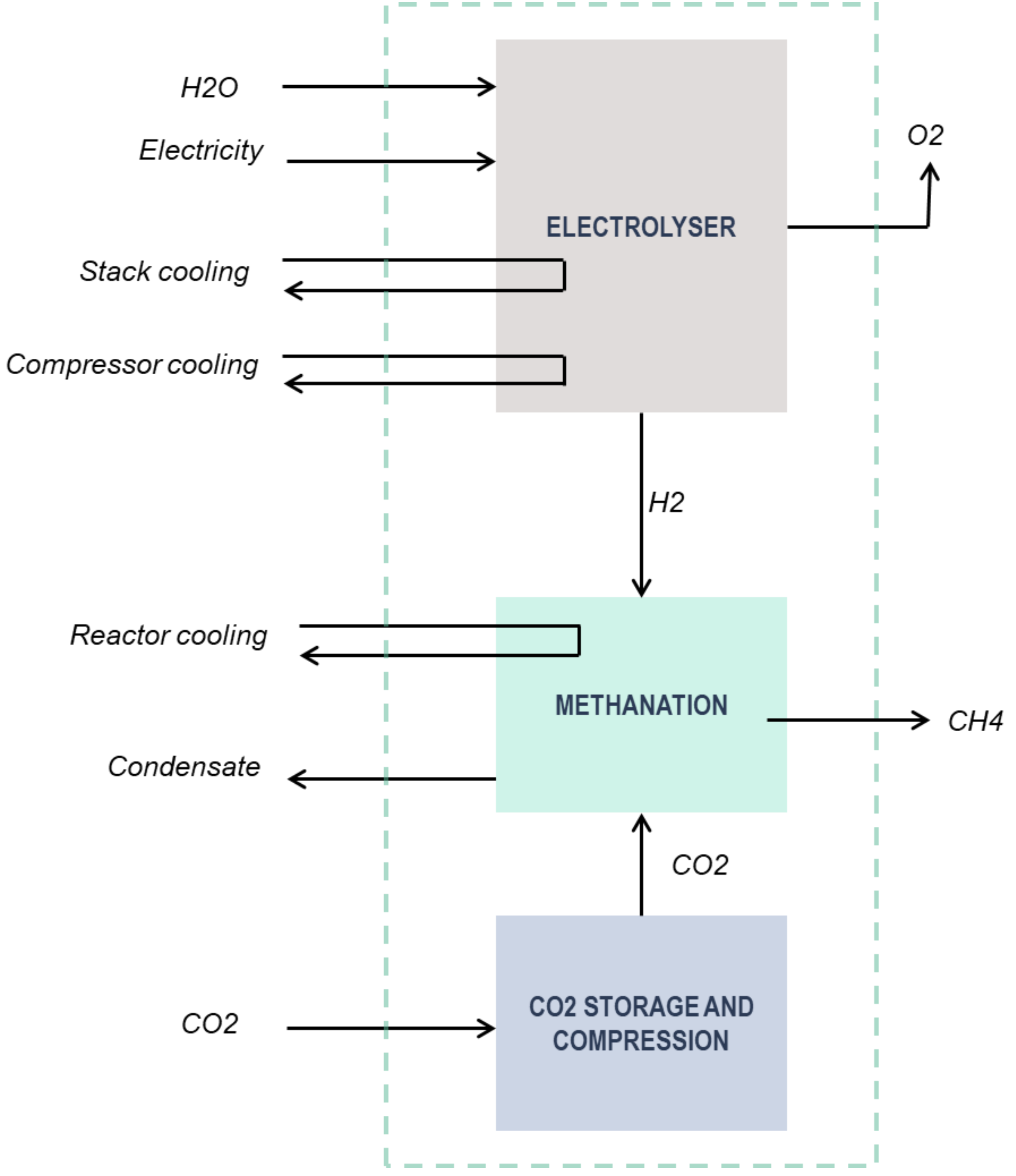

Figure 8. Technical configuration of the proposed plant.

6 Plant profitability analysis

6.1 CAPEX distribution

The total investment cost for the chosen plant configuration in the Meri-Pori region is estimated to be ~47 MEUR, including 20% contingency. Heat pumps and equipment for heat integration are excluded from this cost as well as the cost for land acquisition. The distribution is shown in the figure below:

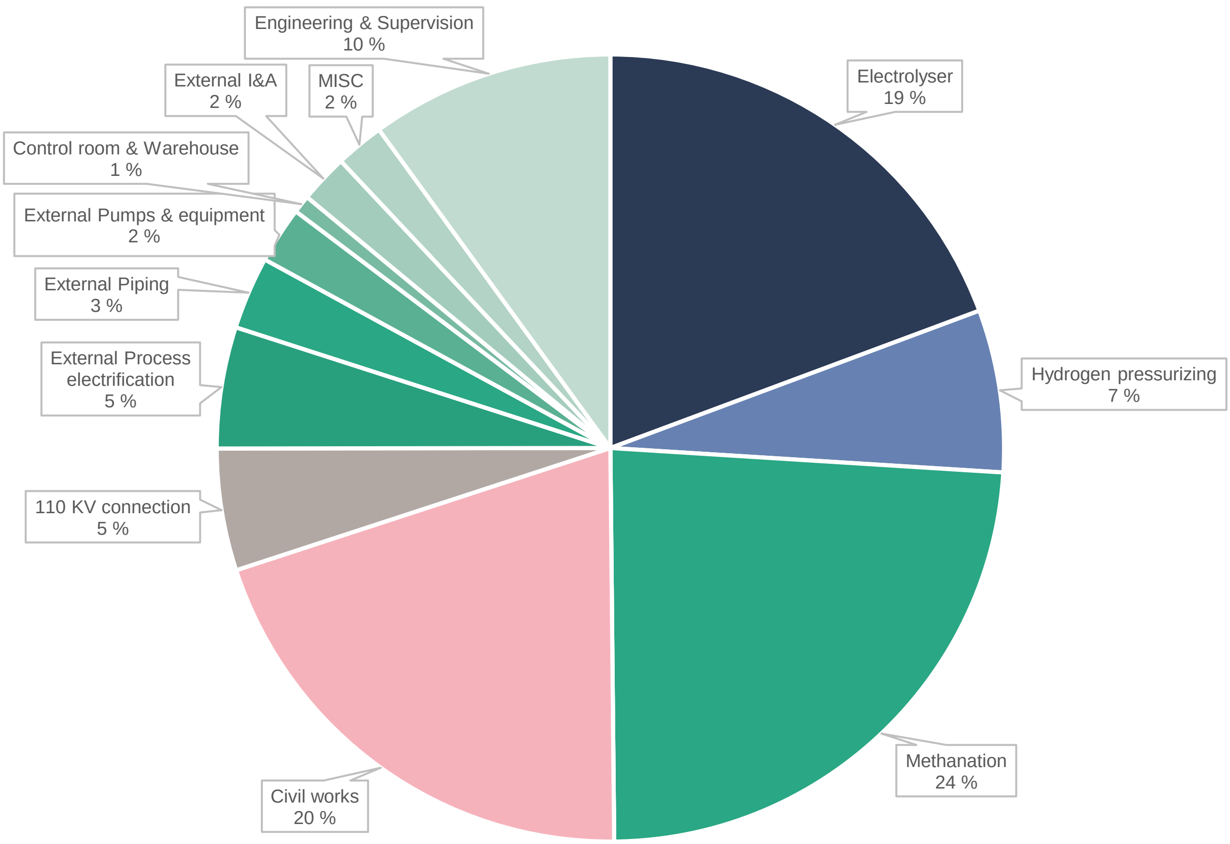

Figure 9. CAPEX Distribution for the assumed plant configuration.

The cost for the electrolyser, the hydrogen compression, and the methanation unit is only 50% of the total investment cost. Generally, when looking into reports and roadmaps regarding green hydrogen or synthetic fuel production plants, the cost share for these main components are significantly higher. Research institutes tend to underestimate the real cost for construction and localization, as this is rarely the main focus in these reports, and no certain location is even considered. However, it is important to be aware of this phenomenon. As in the diagram above, only the civil work is estimated to be 20% and the 110kV connection is 5%. This is common for these kinds of so-called green-field installations and this cost can only be significantly decreased if all infrastructure would already been available. This also mean that even if for example the electrolyser investment cost will decrease with 30% the coming years, the impact on the total investment cost will only be about 6%.

6.2 OPEX distribution

In the figure below, the OPEX distribution for the first year of operation of the plant is shown.

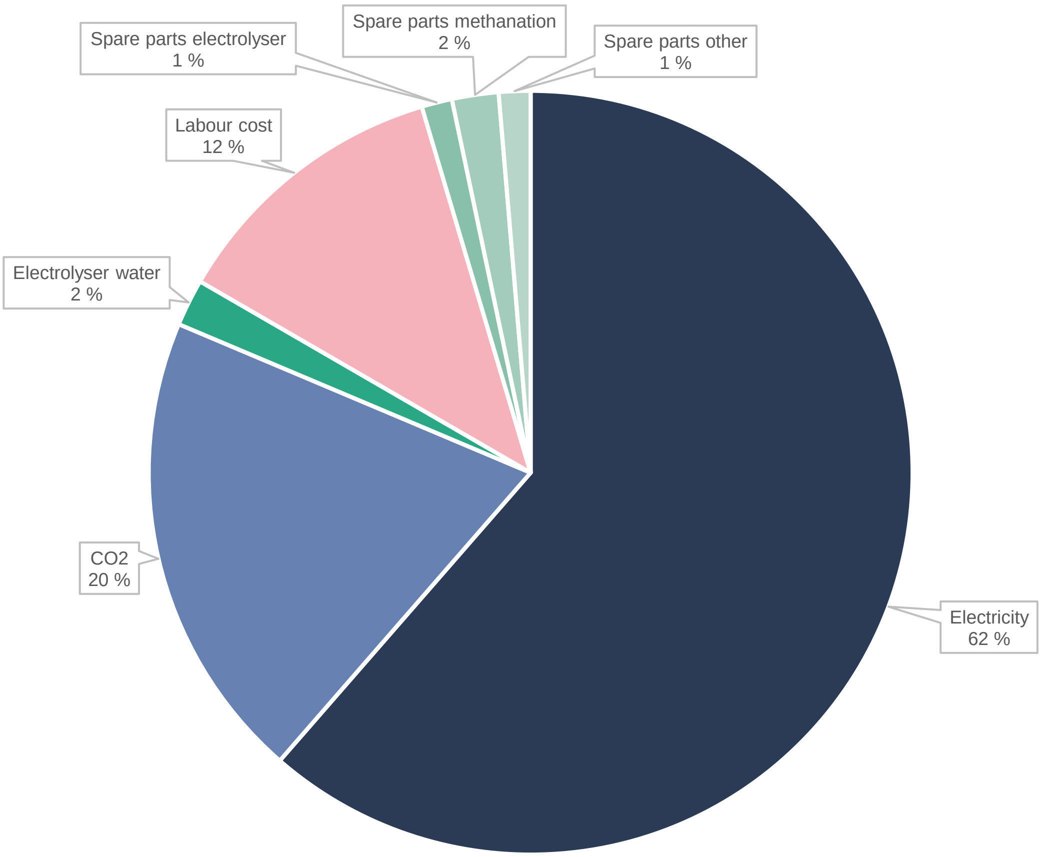

Figure 10. OPEX Distribution for the assumed plant configuration during first year of operation.

The assumed cost for CO_2 is 100 €/t and for electricity 32.50 €/MWh. Running hours is 8000h. The power purchasing stands for more than 60% of the total operational expenses. CO_2 purchasing is also a significant expense.

It should be noted that cost for electrodes replacement is not visible in the OPEX diagram. Typical lifetime of electrodes is about 10 years of continuous operation. Actual lifetime will vary with operational pattern and feed water quality. Estimated future stack replacement cost (electrodes + diaphragm frames) per electrolyser is about 30% of the electrolyser investment cost. Also, the catalyst of the methane reactor has to be exchanged about every fourth year. The cost for this is about 5% of the methane reactor investment cost.

Both electrode and catalyst replacement have been considered in the sensitivity analysis.

6.3 Sensitivity analysis

In this chapter it will be demonstrated how all relevant parameters are affecting the profitability of the plant. The base for the sensitivity analysis is the direct pay-back, i.e., the cost of capital is not considered. Sensitivity analysis will be carried out for the *SNG sales price*, *cost for electricity*, *cost for CO_2*, *waste heat utilization, oxygen utilization*, and *plant running hours*. The base case and changes in parameters will be as per the table below.

Table 3. Parameter values used in the sensitivity analysis for the plant.

Product / item	Base case	Sensitivity analysis
SNG sales price	125 €/ MWh	75-150 €/MWh
Levelized cost for electricity	32.50 €/MWh	17.50 - 40.00 €/MWh
Cost for CO_2	100 €/tCO_2	0-200 €/tCO_2
Waste heat utilization	100 %	0-100 %
Levelized waste heat price	21.5 €/MWh	21.5€/MWh
Oxygen price	0 €/t	20 €/t
Plant running hours	8000h	3000-8000h

100% waste heat utilization will be included in the base case but no oxygen trading. The cost for CO_2 is set to 100 €/tCO_2, as per the discussions in Chapter 4.4.

Levelized cost for electricity refers to the average cost for the assumed running hours. In reality the cost will be fluctuating, depending on the PPA.

Levelized waste heat price refers to the average sales price for the heat for the assumed running hours. As discussed in chapter 5.3, there are different temperature levels for the heat streams and the price usually also varies with the seasons.

A price escalation factor has been used in the calculations of usually **2% per year.** No interest expenses are considered.

6.3.1 SNG Sales Price

In the figure below, the impact on the pay-back time for different sales prices on the SNG is demonstrated.

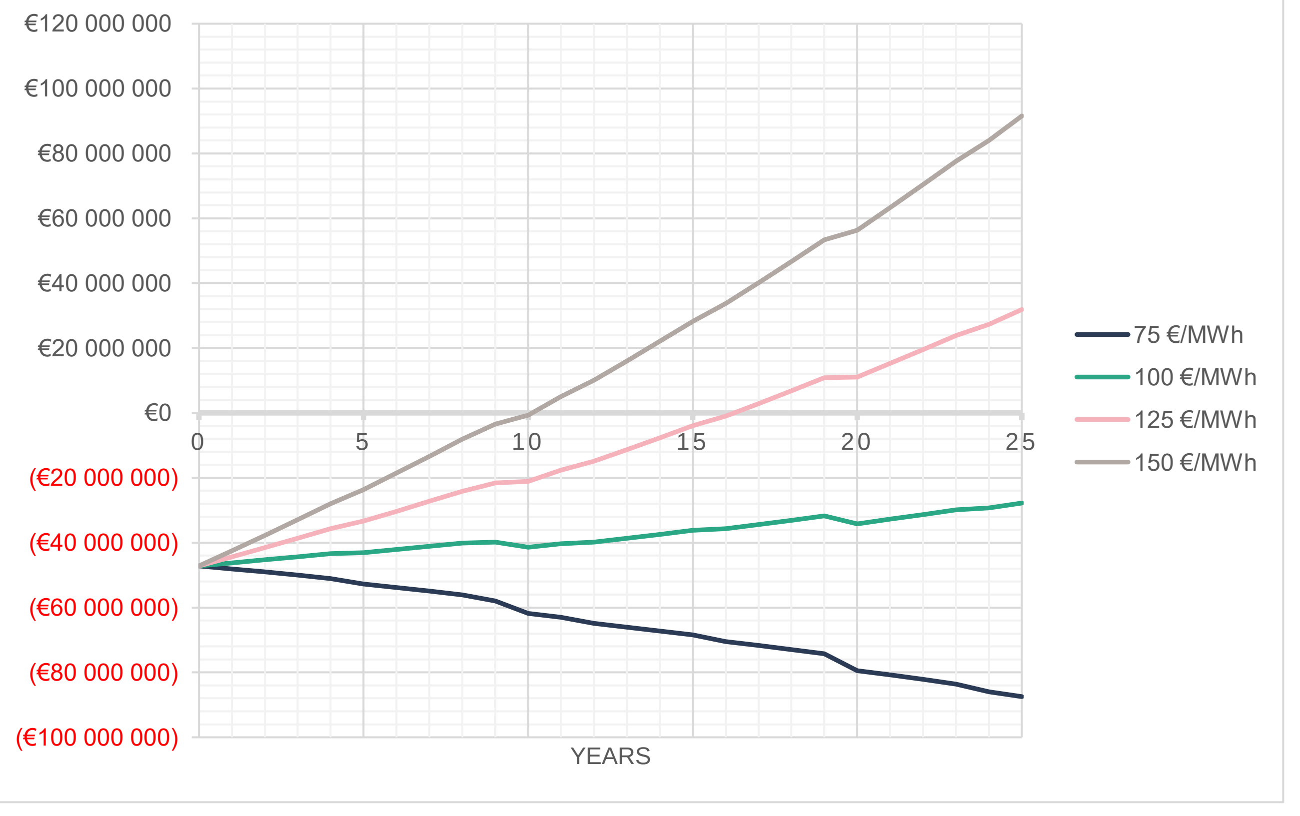

Figure 11. SNG Sales price impact on the pay-back time. (WH: 100% @ 21.50 €/MWh, El: 32.50 €/MWh, CO_2: 100 €/tCO_2, O_2: 0 €/t, RH: 8000h).

A sales price above 125 €/MWh is required, to have an acceptable pay-back time. It is also quite clear that even if the investment cost would be cut by 50%, by investment subsidies or similar, it will still not make the investment profitable for SNG prices below 100 €/MWh, as the positive cash flow is basically too small at this price level.

A SNG price of 75 €/MWh is quite close to what the NG price level could be today, at its best. The plant would be generating a negative cash flow at this level, simply because the cost for electricity is to high compared to the sales price for SNG, even if 100% waste heat utilization is already considered. This means that the price on SNG has to be higher in the future to initiate SNG projects. This can happen through political decision, either directly or indirectly. A direct solution would be a feed-in tariff system, which guarantees a certain sales price for the SNG producer, for a certain period. An indirect solution would for example be tougher CO_2 or excise taxation on fossil-based alternatives, extensive blending obligations, and a decrease in the number of EUAs.

6.3.2 Levelized cost for electricity

As already mentioned in this report, electricity is the largest operational cost for a methanation plant and therefore crucial for the overall profitability. In the figure below, the effect on the pay-back time for different levelized costs on the electricity is shown.

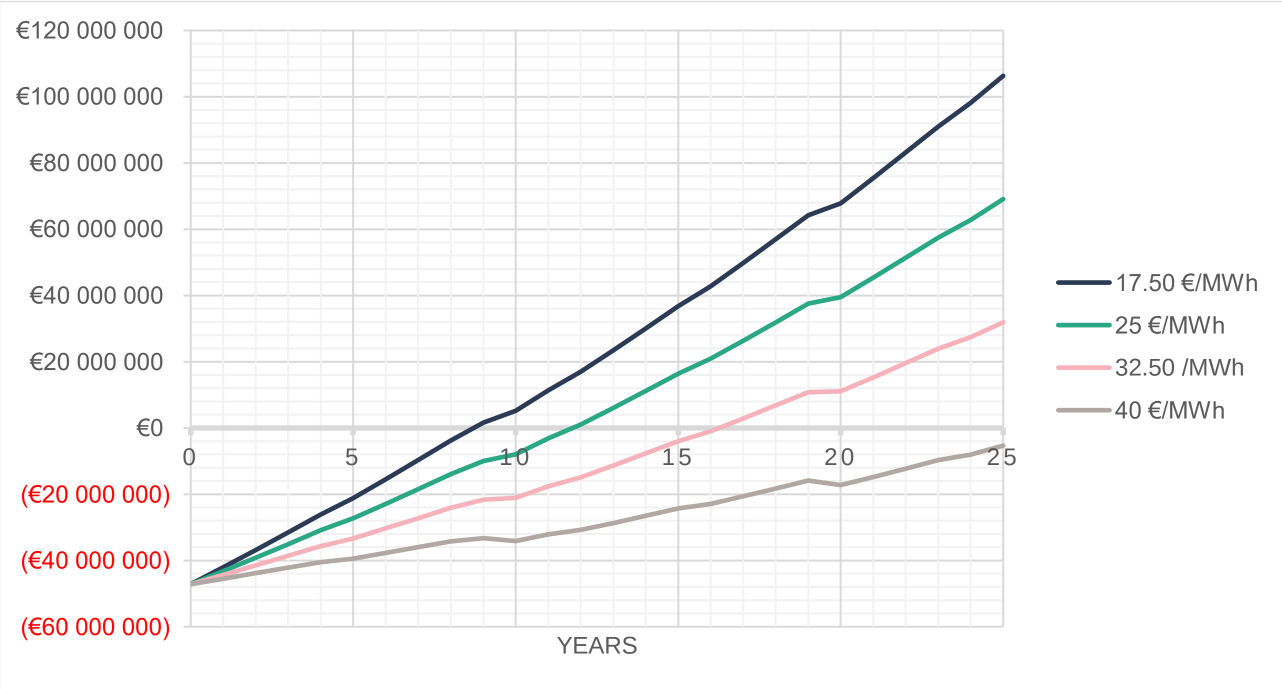

Figure 12. Electricity cost impact on the pay-back time. (WH: 100% @ 21.50 €/MWh, SNG: 125 €/MWh, CO_2: 100 €/tCO_2, O_2: 0 €/t, RH: 8000h).

An electricity cost of 32.50 €/MWh is required to have a reasonable pay-back time, considering that the SNG is sold at 125 €/MWh and 100% waste heat is utilized.

The levelized cost for electricity is very much depending on the running hours, meaning that the plant can either be in operation only when the spot-price is low or operation could alternatively be avoided when the spot-price is high. As the investment cost for a methanation plant is high, the later alternative, to avoid operation only during the most expensive hours, is actually the only operating model that could actually be profitable. This will be shown later in chapter 6.3.6. Therefore, the cheapest alternative in the figure above, an electricity cost of 17.50 €/MWh, is not actually a realistic option as long as the running hours for the plant is 8000h.

It could roughly be estimated that a realistic levelized cost for the electricity in the coming 10 years could be around **30 €/MWh**, with about 8000 running hours per year. This will however require participation in the frequency containment and restoration market as well as a direct connection to the wind farm, in order to avoid grid provider transfer fees and possibly also electricity taxes.

6.3.3 Carbon dioxide cost

After electricity, the cost for captured CO_2 is the second largest operational expense for a methanation plant. In the figure below, the impact on the pay-back time for different CO_2 costs is indicated.

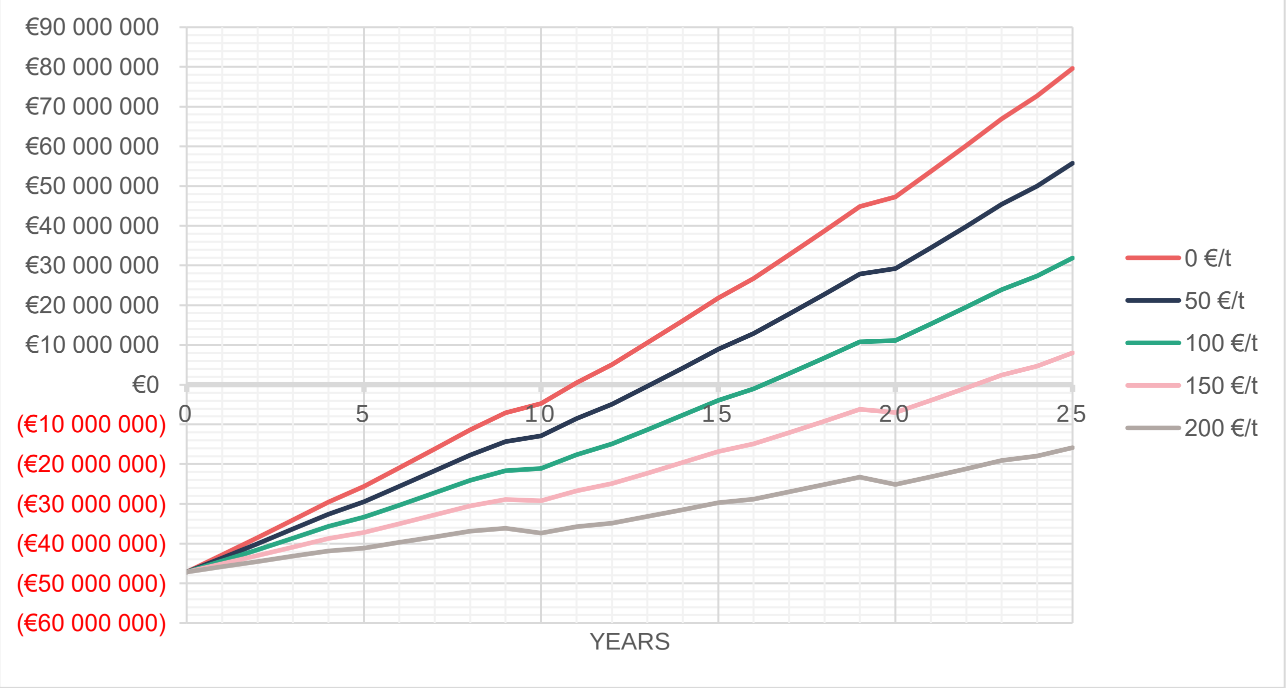

Figure 13. CO_2 cost impact on the pay-back time. (WH: 100% @ 21.50 €/MWh, SNG: 125 €/MWh, EL: 32.50 €/MWh, O_2: 0 €/t, RH: 8000h).

At a price level above 100 €/tCO_2, the pay-back time is extended more and more. A methanation reactor consumes approximately 0.2 tCO_2 per MWh produce SNG. This means that for every 10 €/t increase in the cost for CO_2, the sales margin of the SNG is decreased by 2€/MWh. A change from 100 to 200 €/tCO_2 will thus decrease the SNG margin with 20 €/MWh, and consequently destroy the profitability.

It has to be noted that a price of 125 €/MWh for the SNG has been used. If for example SNG production will be subsided with discounted electricity rather than a guaranteed price system for the SNG, the overall profitability for the plant will be much more sensitive to changes in the CO_2 price, than indicated above.

A price of 0 €/t is basically not a realistic alternative, but represents a situation in where biogas is fed straight into a bio-methanation reactor and therefore no separate carbon capturing is required. However, with bio-methanation the total investment cost will be increased with about 10%. Still, this seems to be a very attractive alternative for a methanation plant.

6.3.4 Waste heat utilization

Waste heat utilization is crucial for the overall profitability. One way to see it would be to consider the methanation plant as both an SNG and heat production plant, rather than just an SNG production plant. In the figure below, the effect on the pay-back time, due to changes in the waste heat utilization rate is shown. Levelized sales price for the waste heat is assumed to be 21.50 €/MWh.

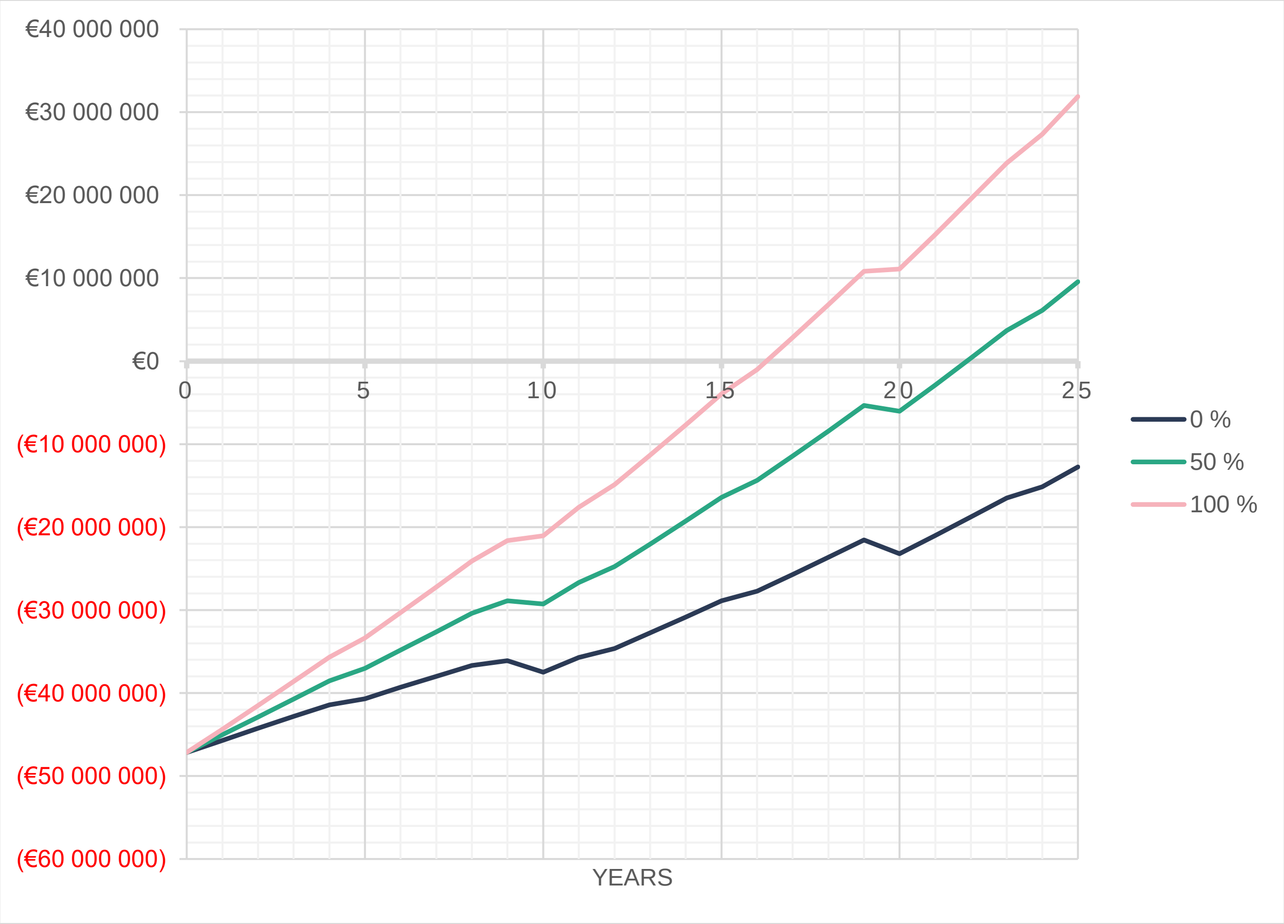

Figure 14. Waste heat utilization impact on the pay-back time. (WH: 21.50 €/MWh, SNG: 125 €/MWh, EL: 32.50 €/MWh, CO_2: 100 €/tCO_2, O_2: 0 €/t, RH: 8000h).

For the base case assumed, the plant could be profitable with 100% waste heat utilization, but without, the pay-back time would be far too extensive.

The same applies for the waste heat as for the CO_2. If SNG production is subsided by electricity discount instead of a feed-in tariff on SNG, the waste heat utilization will be even more important for the overall profitability as its total share of the income will be proportionally higher.

6.3.5 Oxygen utilization

As discussed in chapter 3.4, oxygen utilization is not primarily possible in either Tahkoluoto or Kaanaa. However, in the figure below the effect of trading electrolyser oxygen is shown.

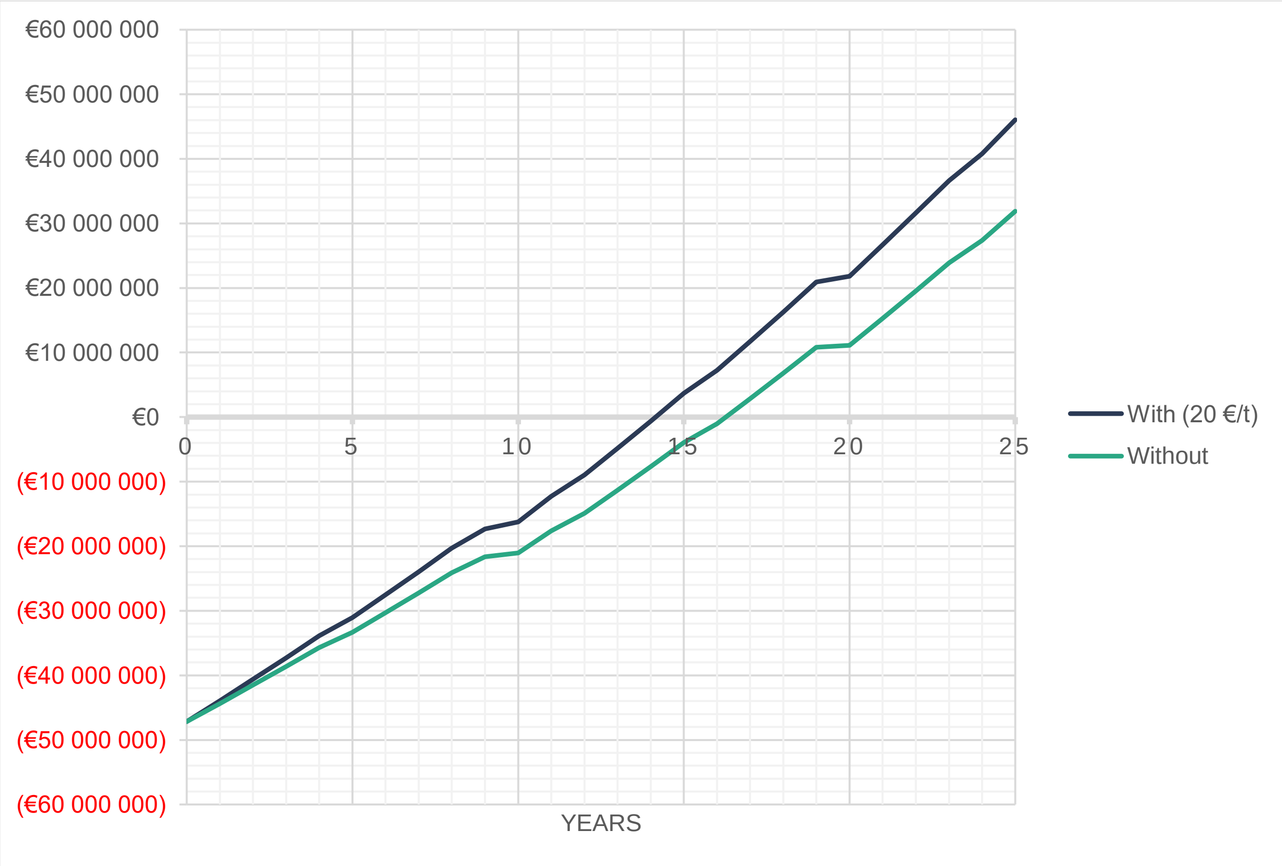

Figure 15. Oxygen utilization impact on the pay-back time. (WH: 100% @ 21.50 €/MWh, SNG: 125 €/MWh, CO_2: 100 €/tCO_2, EL: 32.50 €/MWh, RH: 8000h).

Oxygen utilization will contribute to a better profitability. Nevertheless, a margin of 20 €/t is only possible if a direct connection can be done to an industrial user. If the oxygen has to be transported to the customer, the margin is probably much lower, without an optimized logistic chain. This may sound a little bit strange, as it is widely known that for example the margin of medical oxygen in Finland is high. However, as an electrolyser of this size is producing very large amount of oxygen, only a fraction of it could be traded as medical oxygen to nearby health providers, meaning that the impact on the overall profitability for this plant is negligible. It also has to be mentioned that to enable oxygen capturing from an AEL electrolyser, the CAPEX will increase with about 300 000 €, compared to a situation in where it is dissipated to the atmosphere. Liquefaction and bottling will increase the CAPEX cost even further.

6.3.6 Plant running hours

In the figure below, the payback-time for different running hours and electricity prices are shown.

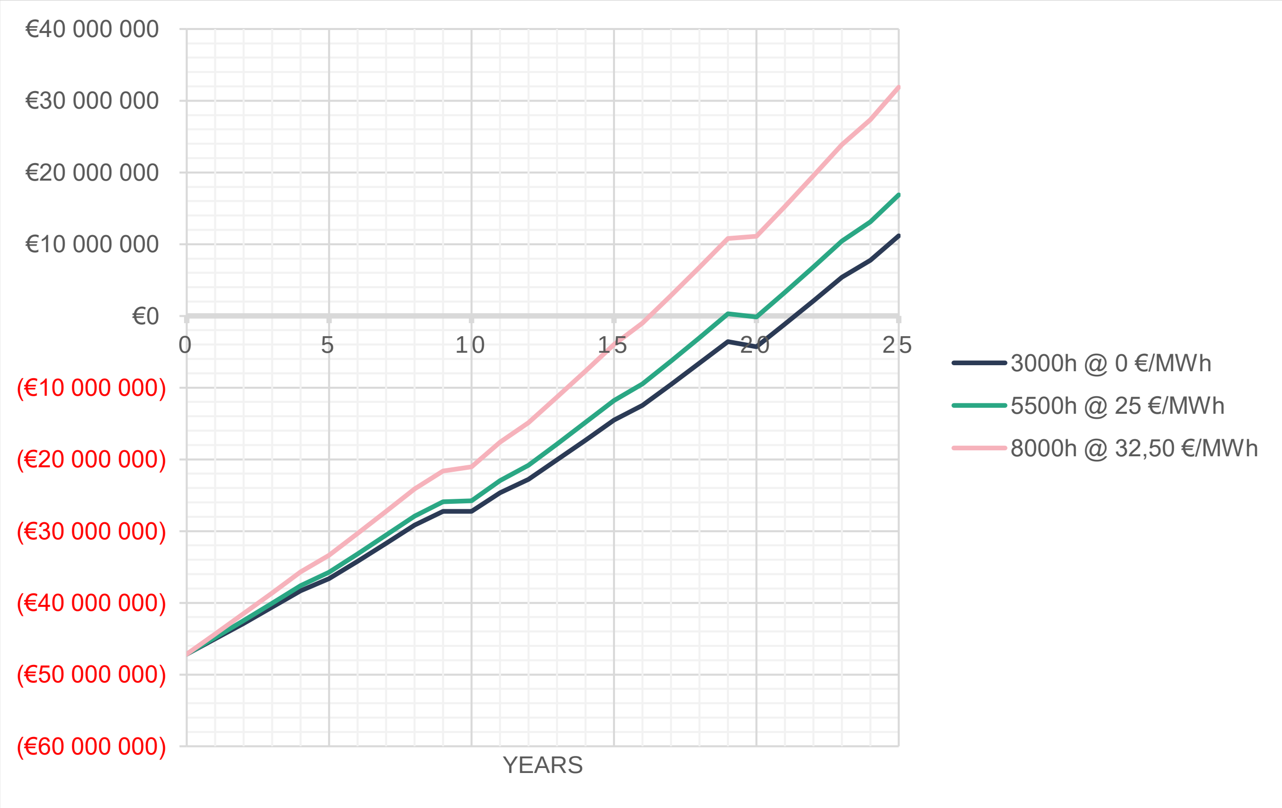

Figure 16. Running hour impact on the pay-back time. (WH: 100% @ 21.50 €/MWh, SNG: 125 €/MWh, CO_2: 100 €/tCO_2, O_2: 0 €/t).

The analysis shows, that it is more profitable to operate the plant for 8000h at an electricity cost of 32.50 €/MWh than for 3000h at a cost of 0 €/MWh. This is in fact a very illustrative conclusion. Power-to-gas plants are usually described as a way to utilize surplus energy by producing methane when the cost for electricity is low. However, the invest cost for such a plant is way too high for using the plant only for 10-20% of the time. To have a reasonable pay-back time, it should be in production about 80-90% of the time. It also has to be said that 3000h and 0 €/MWh is not even a realistic scenario, but used as an example to really demonstrate the importance of sufficient running hours.

8000 hour per year could be very challenging from a wind power producers' point of view, as it would mean that the plant should be in operation also in a situation when the total output from the wind park is actually very low, meaning that the possibility to use the plant for power balance trading is limited if the requirement of 8000 running hours also has to be fulfilled.

7 Conclusions

SNG or other carbon-based synthetical fuels is often described as the missing part for fighting the climate change. However, the production cost of these fuels is very high, primarily due to high electricity consumption and the need for concentrated CO_2 sources.

SNG production is currently not profitable in Finland; the relationship between the sales price of the SNG and the levelized cost for electricity is basically not favorable. This may however change in the future due to political decisions and decreased investment cost for the technology, but it is still important to be aware of the fact, that the SNG market may not necessarily be as extensive as usually anticipated. There are many competing technologies such as electrification, hydrogen, ammonia, conventional biogas, renewable liquid fuels (e.g., HVO).

Even carbon capture and **storage** (CCS) could be seen as a competing technology to SNG production, which is a type of carbon capture and **utilization** (CCU). This is because, the amount of physical CO_2 emission from burning synthetic natural gas and fossil natural gas is equal. The difference is that the CO_2 in the fossil natural gas is of non-renewable origin, while for SNG, the CO_2 is captured from the air (or just before it enters the air), making it carbon neutral. However, if the captured CO_2 is stored, instead of utilized in fuels, the GHG reducing impact will be negative, not only neutral. In other words, the GHG reduction achieved by using SNG, may actually be comparable to a situation in where fossil based natural gas are used, and the corresponding amount of CO_2 is captured and stored. Moreover, the renewable electricity required for the SNG production will in that case be saved. This means, that if excess energy is not available, CCS and the use of fossil natural gas, could from GHG reduction perspective, actually be seen as a better alternative than SNG production. It should however be noted, that the Oil & Gas industry is also emitting large amount of CO_2, so general conclusions should be avoided, without a case specific carbon footprint analysis. It also has to be said that there are several technical challenges related to the CO_2 storage, so it is not a viable alternative in all cases. Still, this is a very demonstrative example of the fundamental challenges related to SNG production.

Nevertheless, the fact that SNG can be used in many existing applications while the traditional oil & gas extraction will probably be reduced in the future, is an advantage that shall not be underestimated. To extend the use of direct electricity, hydrogen, and even ammonia will require large infrastructural investments. As it is today, there are still no transportation or consumer market for green hydrogen or ammonia in Finland. These products are exclusively used in the industrial sector.

It should also be noted, that the transition from natural gas to renewable alternatives will probably occur gradually, meaning that fossil natural gas could be blended with renewable SNG or biogas. With a share of for example 5%, a price of even 150 €/MWh for the SNG, wouldn't affect the average consumer price significantly.

Another important conclusion of this study is that if SNG production turns out to be profitable in the future, the Meri-Pori region could be a very suitable location for this type of plant, as basically all required parts could be found in the same area; Wind power, CO_2 capturing, LNG terminal, and district heating network. The only part that is missing is a large-scale oxygen consumer, but this is also the least important.

As it looks for now, the primary location for a methanation plant in Meri-Pori would be Kaanaa, as the availability of CO_2 at site and the possibility for 100% heat utilization outcompetes the possibility to have a direct power connection to the Tahkoluoto wind park. However, if some synergies regarding CO_2 purchasing could be found with Critical Metals and their future vanadium recovery plant in Tahkoluoto, this location would be an equally good alternative as Kaanaa.

An alkaline electrolyser of about 20 MW and a conventional methanation unit of corresponding size (10 MW) is currently seen as the best technology choice for this location. However, this could change over time, and is also depending on how SNG production will be subsided in the future. Therefore, it is recommended that both PEM and bio-methanation is fairly evaluated also in the eventual next phase of this study. Many reports also state that SOEC will be the dominating electrolyser technology for synthetic fuel production in the future, so this should be kept in mind.

The strategy for electricity purchasing and/or the integrated operational model for this plant and the wind park in Tahkoluoto will be essential for the overall profitability. It is important to be able to decrease the levelized cost for electricity but at the same time it is important that the plant is in operation more than 80% of time, otherwise it will not be possible to have an acceptable pay-back time. The challenges are that high utilization rate, spot-price optimization, and successful balance power trading is hard to achieve at the same time.
Even if the operational model could improve the profitability, EU or governmental subsidies will still be required for a profitable production. It is highly unlikely that the general market price development will be sufficient for making SNG production profitable in near future.

8 Executive summary

Power-to-gas processes, such as production of for example renewable synthetic natural gas from electrolyser hydrogen and captured carbon dioxide, are expensive and energy consuming processes. A methanation plant produces hydrogen, methane, waste heat, and oxygen. Hydrogen is globally the most valuable product of these, with a sales price of 250 €/MWh for consumer when used as a transportation fuel, and 80-120 €/MWh, when used in the industry. However, currently in Finland there are basically no hydrogen-fuelled vehicles and all large-scale industrial users have their own on-site production. Thus, the primary sales product for a methanation plant located in the Meri-Pori region, would currently be synthetic natural gas (SNG). The market for hydrogen will not open up before the chicken-and-egg strategy problem, related to hydrogen utilisation in the Finnish transport sector, has been solved.

The market price for SNG in Finland can be assumed to be equal to the price of biogas, which is currently around 84 €/MWh (VAT 0%), when used as a transportation fuel. This price level will not be sufficient for making methanation projects profitable. A price level of about 125-150 €/MWh would be needed, depending on how efficiently the by-product are utilized. This means, that production subsidies will be required. One alternative could be a feed-in tariff system, in which the producer always gets a guaranteed price for the SNG.

If the general profitability for SNG production is improved, Meri-Pori could be a very attractive location for a methanation plant, as basically all required stakeholders and infrastructure could already be found from there, such as dedicated wind power, CO_2 capturing, district heating, and LNG distribution.

There are two possible locations for the plant in Meri-Pori; Tahkoluoto and Kaanaa. The advantage with Tahkoluoto is that grid transfer fees can be avoided with a direct connection to Hyötytuuli Oy's wind power station. However, the possibility to utilize waste heat would be very limited in this location. In Kaanaa, it is the other way around; 100% waste heat utilization is possible, at least in theory, but transfer fees has to be paid for the electricity, as the plant would be connected to Porin Energia's 110 kV system. The availability of CO_2 is probably not a problem in neither of the locations in the future. In Kaanaa, a direct connection to BioEnergo's CO_2 capturing unit can be arranged and in Tahkoluoto, synergies with Critical Metals and their CO_2 purchasing could certainly be found. The availability of CO_2 is the most crucial factor when evaluating the feasibility of a methanation plant, but in the Meri-Pori region, there are already several possibilities for this.

The total plant investment cost in this area is estimated to be 47 MEUR, including 20% contingency, but excluding plot acquisition costs. It should be noted that the electrolyser, the hydrogen compression, and the methanation unit stands for only 50% of the total investment cost, as there are many other cost items, such as civil works and high voltage infrastructure to consider. It should be noted that these types of costs usually tend to be underestimated in pre-feasibility studies and research reports in this field.

Based on the profitability analysis in this study, an SNG price of 125 €/MWh would be required, to have a reasonable pay-back time (~15 years). This assumes that all waste heat will be utilized, the levelized cost for electricity is 32.50 €/MWh, and the cost for CO_2 is 100 €/t. As already stated earlier in this report, this will currently require production subsidies.

The conclusion of this study is thus, that even if SNG production is not currently profitable in Finland, it may still be it in the future, through political decisions and production subsidies. If, or when this happens, Meri-Pori is probably one of the most appropriate locations for this kind of plant.

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