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Refinery Decarbonization in Austria: A Techno-Economic and Ecological Assessment of Green Hydrogen Opportunities through Import and Local Production

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supervised by
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Affidavit

I, **JELISAVETA PAVLOVIC, MSC**, hereby declare

1. that I am the sole author of the present Master's Thesis, "REFINERY DECARBONIZATION IN AUSTRIA: A TECHNO-ECONOMIC AND ECOLOGICAL ASSESSMENT OF GREEN HYDROGEN OPPORTUNITIES THROUGH IMPORT AND LOCAL PRODUCTION", 107 pages, bound, and that I have not used any source or tool other than those referenced or any other illicit aid or tool, and
2. that I have not prior to this date submitted the topic of this Master's Thesis or parts of it in any form for assessment as an examination paper, either in Austria or abroad.

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Abstract

Renewable energy is rapidly transforming our planet, significantly reducing carbon emissions across various sectors through increased clean energy capacity. However, "hard-to-abate" industries such as refining, steel, plastics, and heavy transport fuels require innovative solutions due to their high-temperature processes. This thesis explores sustainable methods of hydrogen generation, focusing on electrolysis, which emerges as an environmentally friendly method for producing high-purity hydrogen when powered by renewable electricity sources like solar or wind energy. Green hydrogen is identified as a key solution for decarbonizing the refining industry by replacing grey hydrogen used in hydro-processing and hydro-sulfurization. The study aims to develop a comprehensive strategy for Austria's refinery sector transitioning to green hydrogen, assessing the feasibility of meeting current demands with hydrogen from renewable sources. An analysis of existing hydrogen production at the Schwechat refinery is conducted, evaluating the potential for green hydrogen production through solar photovoltaic and wind energy, including the calculation of levelized costs under various scenarios. The assessment considered factors such as photovoltaic energy generation potential, electrolyzer technology, carbon dioxide emissions avoided, and the costs required for green hydrogen production. In addition, opportunities for hydrogen imports from North Africa is evaluated due to its superior solar and wind resources. This thesis includes a comparative analysis between local production in Austria and potential imports from Tunisia, focusing on levelized costs and also life cycle assessments of green hydrogen to evaluate environmental impacts and greenhouse gas abatement costs. Key findings reveal electricity costs as the largest component of hydrogen's levelized cost, indicating that the cost-effectiveness of production is sensitive to electricity prices. While North Africa presents a competitive advantage due to its greater renewable energy potential, importing hydrogen incurs higher capital costs associated with political and logistical uncertainties. Lastly, the greenhouse gas abatement cost analysis indicates that for green hydrogen to compete with cheaper grey hydrogen, significant increases in carbon dioxide pricing will be necessary in the near future.

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List of Abbreviations

AE – Alkaline Electrolyzer

BoP – Balance of the Plant

CAPEX – Capital expenditure

CCS – Carbon Capture and Storage

CO2 – Carbon dioxide

DNI – Direct Normal Irradiation

DOE – Department of Energy

EEX – European Energy Exchange

EHB – European Hydrogen Backbone

EU – European Union

EUR – euro

FLH – Full Load Hours

GHG – Greenhouse Gas

GHI – Global horizontal irradiation

GIZ – Deutsche Gesellschaft für Internationale Zusammenarbeit

GW – Gigawatt

H2 – Hydrogen

HCl – Hydrochloric acid

ICE – Intercontinental Exchange

IEA – International Energy Agency

IRENA – International Renewable Energy Agency

Kg – Kilogram

KOH – Potassium Hydroxide

kW - Kilowatt

kWh – Kilowatt hour

LCOE – Levelized Cost of Electricity

LCOH – Levelized Cost of Hydrogen

LH – Liquid Hydrogen

LHV – Lower Heating Value

LNG – Liquefied Natural Gas

LOHC – Liquid Organic Hydrogen Carrier

MCH - Methylcyclohexane

Mt – Megaton

MW - Megawatt

MWh – Megawatt hour

NaCl – Sodium Chloride

NaOH – Sodium Hydroxide

O&M – Operation and Maintenance

OPEX – Operating expentidure

PEM – Polymer Electrolyte Membrane

PPA – Power Purchase Agreement

PSA – Pressure Swing Adsorption

PR – Performance Ratio

PV – Photovoltaic

PVGIS – Photovoltaic Geographical Information System

RED – Renewable Energy Directive

RFNBO – Renewable Fuels of Non-Biological Origin

SMR – Steam Methane Reforming

SOEC – Solid Oxide Electrolysis Cell

TSO – Transmission System Operator

TWh – Terawatt hours

USD – the U.S. dollar

WACC – Weighted Average Cost of Capital

YSZ – Yttria-stabilized zirconia

1. Introduction

Hydrogen has been utilized as an energy carrier for decades, and its demand reached 95 million tonnes in 2022—about 2.5% of total global energy consumption (IEA, 2023a). Predominantly used in industrial settings, hydrogen's main applications include refining processes in the petrochemical industry, as well as the production of methanol and ammonia, making these sectors the primary consumers of hydrogen today. An examination of hydrogen production sources reveals a significant dependency on fossil fuels: approximately 47% of hydrogen is derived from natural gas, 22% from oil, 27% from coal, and a mere 4% from electricity, with only a small fraction of this electricity being sourced from renewable energy on a global scale (IRENA, 2022a). Consequently, most of the hydrogen produced today is categorized as “grey hydrogen”, with “green hydrogen”—produced through environmentally friendly processes—constituting only a small share of the total production. In the refining sector, the use of hydrogen surpassed 41 million tonnes in 2022, which represents 43% of the global hydrogen demand (IEA, 2023a). In the future, the demand for climate-neutral hydrogen and other gaseous energy carriers will continue to be significant, especially for certain industrial applications.

There is necessity for climate change and the movement towards net-zero is now embraced. Production systems are as well being transformed. Refineries have also started in every way to decarbonize their operations. The green hydrogen plays a crucial role in the transition process from an energy system with high emissions. Green hydrogen will be important in industrial processes where alternative energy sources cannot meet material process needs or high-temperature requirements. The focus lies on producing green hydrogen through the establishment of electrolyzers.

The European Union (EU) has ambitious decarbonization targets and aims to become carbon neutral by 2050 (GIZ, 2021). The European Union has a definitive strategy for hydrogen implementation, aiming for Europe to produce 10 million tonnes of green hydrogen on-site and import another 10 million tonnes annually. The EU is already working to implement these two strategies. Given the strong pipeline network, imports are expected to primarily occur via pipelines (European Comission, 2020).

There is a gap in forecast scenarios among different agencies. Today's hydrogen share in the energy system is around 3%. The International Energy Agency (IEA) predicts this will increase to 10% by 2050 (IEA, 2021). On the other hand, the International Renewable Energy Agency (IRENA) offers similar projection, with hydrogen reaching a 12% share by 2050 (IRENA , 2021b). Both agencies assume a linear growth rate over the next 30 years, consistent with the steady growth observed in recent years. Scenario of Hydrogen council is slightly more optimistic which is around 22% (Hydrogen Council, 2021). Deloitte and McKinsey have the most optimistic scenario with a hydrogen share between 30-65% in the global energy system by 2050 (Deloitte, 2023) (McKinsey , 2024).

Assuming a moderate perspective, it can be estimated that the hydrogen share in the energy mix by 2050 would be around 15-20%. This represents a significant contribution to the overall energy system.

Considering the potential to import, particularly from regions abundant in renewable sources like Africa, presents an opportunity for global sustainable progress, especially for developing economies (Fraunhofer, 2021).

Renewable hydrogen is anticipated to be crucial in reducing carbon emissions in the difficult-to-decarbonize industrial and transport sectors. However, currently, the production of renewable hydrogen is too costly to implement on the necessary scale. In response, the European Union has dedicated a substantial budget to decrease the production costs, aiming to make renewable hydrogen economically competitive with the traditional "grey" hydrogen (Hassan et al., 2024). Concurrently, the EU has introduced stringent regulations that mandate an increase in the use of renewable hydrogen by industrial entities in the upcoming years. The criteria to be eligible for EU subsidies are quite stringent and encompass a broad range. Fully understanding the requirements to access these subsidies is essential for renewable hydrogen producers to thrive. Successfully navigating these regulations not only enables producers to leverage the available financial support but also enhances the utilization of renewable energy sources that might otherwise be underused (Menon Economics, 2023).

Refineries represent a hard-to-abate sector, with significant hydrogen usage primarily derived from natural gas reforming for hydro-processing. To reduce the carbon

footprint and align with EU goals, it is crucial to consider replacing natural gas with green hydrogen (IEA, 2023a). In this thesis, explored are two options for achieving this transition: importing green hydrogen from North Africa versus local production within the EU.

1.1 Core Objectives

This work aims to explore potential strategies for decarbonizing the refinery in Schwechat using green hydrogen to meet policy targets. The primary objective is to analyze and compare the feasibility of two approaches for Austria: domestic production vs. importing green hydrogen. This comparative analysis focuses on producing green hydrogen locally in Lower Austria versus importing it from Tunisia, evaluating both options in terms of total costs and renewable electricity potential. Additionally, the objective is to analyze the emissions savings benefits of replacing grey hydrogen with green hydrogen.

The thesis aims to address the following questions:

- In what ways can green hydrogen be produced so that it aligns with the EU Delegated Act?
- What is the current demand for hydrogen in the OMV refinery in Schwechat and how much of this demand can be fulfilled by green hydrogen?
- What is the Photovoltaic (PV) potential of the chosen area in Austria, and how much electricity can be generated to meet the electrolyzer requirements for green hydrogen production?
- What are the suitable electrolyzer types for green hydrogen production in the chosen area?
- Exploring different the possibilities of electricity sources for Austria: electricity from the grid, engaging in Power Purchase Agreements (PPAs), or investing in a new PV and wind farm in Austria, which approach would yield the most cost-effective green hydrogen production?
- What are the possibilities and challenges associated with importing green hydrogen from North Africa?

- What is the Levelized cost of hydrogen (LCOH) of green hydrogen derived from domestic PV and wind -generated electricity and imported green hydrogen from North Africa (compressed and transported via pipeline)?
- What is the Greenhouse Gas (GHG) abatement cost associated with transitioning from grey to green hydrogen?
- What are the best options for green hydrogen supply to refineries based on the lowest LCOH cost?

1.2 Method of Approach

The aim is to explore a range of scenarios for green hydrogen production and supply the refinery Schwechat and to analyze and compare their respective advantages and disadvantages.

The methodology in this thesis encompasses the detailed calculation of the LCOH, which accounts for all expenses involved in the hydrogen production process. Initially, the analysis centers around assessing the potential of renewable electricity generation and determining the Levelized Cost of Electricity (LCOE), a crucial element of production costs. The primary energy source for the hydrogen system is considered from locally generated renewable energy from solar and wind power plants. By factoring in both capital and operational expenditures, the total costs linked to hydrogen production under various scenarios can be deduced.

There are two main scenarios: one involves green hydrogen production in Austria, while the other involves production in North Africa (Tunisia) with import to Austria via pipeline.

In the scenario involving imports, it is assumed that hydrogen pipelines will be constructed using materials and methodologies as those used for natural gas (European Hydrogen Backbone, 2021a). The economic competitiveness of the scenarios depends on fostering favorable conditions for Renewable Energy Sources (RES). Crucial factors such as the distance between the export and import country, Tunisia and Austria, alongside associated transportation costs, are pivotal considerations for hydrogen import.

The economic assessment unfolds in multiple stages. Initially, the computation of the LCOE is based on regional RES potential, laying the groundwork for comprehensive LCOH calculations. The next step involves calculating the production costs of green hydrogen, which includes assessing both the capital expenditure (CAPEX) and operating expenditure (OPEX). Additionally, in the context of substituting gray hydrogen with greener alternatives at the refinery, abatement costs are factored in, encompassing carbon dioxide (CO2) pricing and life cycle emissions associated with green and grey hydrogen production.

In the proposed methodology, first a comprehensive literature review was initially conducted, focusing on EU legislation and regulations. Subsequently, a detailed comparative analysis was undertaken to explore costs and renewable energy potential between import and local production of green hydrogen. Special attention is given also to factors like increased political risks associated with import from North Africa. An LCOH analysis was performed to evaluate and address the research questions.

1.3 Structure

The Chapter 1 delves into the initial literature review, followed by the Chapter 2 emphasizing the EU regulations and hydrogen strategy, including compliance with regulations and targets. The Chapter 3 explores various hydrogen production methods, as well as hydrogen transportation and potential infrastructure implications and use of hydrogen. A dedicated section covers the required electrolyzer capacity for refinery operations. Then, the analysis in Chapter 4 covers hydrogen production within Austria, assessing the solar and wind energy potential in the region. The Chapter 4 also delves into the import scenario and energy potential in Tunisia. This is followed by a comprehensive explanation of the methodology for carrying out calculations. The Chapter 5 outlines all costs, encompassing both CAPEX and OPEX. Additionally, Chapter 5 contains the results obtained from the research findings. Chapter 6 analyzes GHG emissions and the associated abatement costs. Finally, the concluding section summarizes the key discoveries and main limitations of the thesis. It also identifies areas for future research.

1.4 Major Literature

A comprehensive literature review was conducted, drawing valuable insights from sources such as Hydrogen Europe, EU Commission documents, and the Renewable Energy Directive to understand the hydrogen landscape in Europe, strategy and associated regulations. Hydrogen Europe proved the criteria for hydrogen to be classified as Renewable Fuels of Non-Biological Origin (RFNBO) and contribute to the fulfillment of EU targets. Additionally, reports from IEA and IRENA offered various insights on in-depth data concerning green hydrogen and renewable energy. When it comes to hydrogen import and transport options, Deloitte and European Hydrogen Backbone offered highly informative reports. This information was further enhanced with papers from various journal articles and relevant books to ensure a well-rounded understanding of the subject matter.

In the analysis of levelized cost of green hydrogen, Moradpoor et al. (2023) concluded that scenarios based on investing in power plants produce green hydrogen with lower ongoing operational costs than those based on power purchase agreements. However, such scenarios have a higher breakeven price, and they found the cheapest green hydrogen would be produced by powering an electrolyzer with a baseload PPA. They also found that employing a 600MW compressed air energy storage system can decrease grid reliance by 7%.

Dependency on the grid was also examined. Moradpoor et al. (2023) showed that when hydrogen production facilities have a reduced dependency on purchasing electricity from the market, they benefit financially due to the lower electricity purchase cost. There is additional benefit seen in case of selling generated electricity to the market, especially when market prices are high.

Nicita et al. (2020) explored the LCOH together with investing in solar photovoltaic. As renewable sources become more prominent, hydrogen production via water electrolysis is poised to play a vital role in meeting increasing global demand. Nicita et al. (2020) evaluated the economic and technical feasibility of a small-scale green hydrogen production system in Messina, Italy using renewable electricity from a 200 kW photovoltaic plant and a 180 kW electrolyzer. The findings show that investment in such system can be profitable, especially when hydrogen is sold as a feedstock and

oxygen used for medical applications. Da Silva et al. (2022) evaluated to use the oxygen generated from electrolysis for carbon capture in the refinery, enhancing overall efficiency and sustainability.

Several authors examined the possibility of replacing the hydrogen production capacities in petroleum refineries with green hydrogen. Joydev et al. (2021) explored the feasibility of switching to green hydrogen using solar photovoltaic powered Alkaline Electrolyzer (AE). They concluded that the switch is technically viable, provides significant CO2 reduction of 56.3 metric tonnes per year and it is cost competitive, especially through support of India's national hydrogen mission. Achieving this would require 211 GWp of solar PV plants and an investment of 136.21 billion USD to achieve the transition. The LCOH of green hydrogen ranges from 2.2 to 8.6 USD per kilogram of hydrogen. Da Silva et al. (2022) evaluated hydrogen production via water electrolysis using wind energy to reduce greenhouse gas emissions from an oil refinery and facilitate the integration of high wind energy penetration into the electric power system. Six scenarios were developed to compare different technological setups, with plans to use the oxygen co-produced by electrolysis for carbon capture in the refinery's Fluid Catalytic Cracking unit.

North Africa is identified as a promising future producer and exporter of green hydrogen, thanks to its close proximity to Europe and vast solar and wind energy resources (GIZ, 2021). Currently, there is significant variation in the estimated costs of hydrogen production. The data differ based on the types of costs considered: some studies include both production and transportation costs, others only provide total import costs, and some do not specify the detailed cost components (GIZ, 2021). According to GIZ, the cost range for importing hydrogen from North Africa to Germany is substantial, the cost of importing hydrogen from North Africa to Germany ranges from approximately 1.35 to 5 EUR per kilogram, highlighting a variation of around 3.65 EUR per kilogram in the considered estimates. Timmerberg (2019) explored the potential for hydrogen production in North Africa, considering its integration into existing gas pipelines. Findings reveal that the levelized hydrogen production costs range from 1.5 to 3.3 EUR per kilogram of hydrogen (EUR/kg of hydrogen) and the minimum transport costs are estimated at 0.3 to 0.6 EUR/kg.

Therefore, hydrogen could be competitively supplied to Central Europe for a total cost of 1.8 to 4 EUR/kg of hydrogen.

According to the GIZ report (2021), the estimated generation costs of green hydrogen in Tunisia vary between 3 to 4 EUR/kg of hydrogen. By 2050, the lowest estimated costs for hydrogen generation are projected to be 1.8 EUR/kg of hydrogen. Gado et al. (2024) conducted a comprehensive study on the LCOH from solar and wind sources in various African countries. Their analysis encompassed estimating electricity and hydrogen production costs, carbon dioxide reduction, and projected LCOH values by 2030 for each country. Among their findings, the LCOH for Tunisia was calculated at 5.42 USD/kg for solar and 12.11 USD/kg for wind energy sources.

2 The European Hydrogen Strategy

Governments, industry leaders, and stakeholders worldwide are intensifying efforts to enable the ongoing shift towards sustainable energy, striving to achieve carbon neutrality. This endeavor aligns closely with the objectives outlined in the Paris Agreement, aiming to limit global temperature rise to below 2°C. Achieving these goals necessitates a fundamental transition from fossil fuel-dependent systems to those powered by low-carbon alternatives such as renewable energy sources (Huang et al, 2021).

Within the EU there is a focus on the advancement of renewable hydrogen, primarily sourced from wind and solar energy. This strategic direction capitalizes on Europe's strong industrial opportunities in the production of electrolyzers, which will create new employment opportunities and foster economic expansion within the EU.

The EU has set out ambitious targets for renewable hydrogen deployment, outlining a phased approach spanning from 2020 to 2030. In the initial phase (2020-2024), the goal is to install at least 6 GW of renewable hydrogen electrolyzers, aiming to generate up to 1 million tonnes of renewable hydrogen. Subsequently, in the second phase (2025-2030), the aim is to seamlessly integrate hydrogen into the broader energy system, with plans that involve the installation of a minimum of 40 GW of renewable hydrogen electrolyzers, with the target of producing as much as 10 million tonnes of renewable hydrogen within the EU by 2030 (European Comission, 2020),

Moreover, in March 2022, the European Commission's REPowerEU communication reinforced these objectives. It specifically addressed the urgency of reducing the EU's reliance on natural gas imports from Russia. By 2030, REPowerEU plans to add 20 million tons of renewable hydrogen to the targets of the European Hydrogen Strategy, with 10 million tons produced within Europe and 10 million tons imported from other countries (Federal Ministry Republic of Austria, 2022).

To realize these objectives, the EU is undertaking key actions and investments, including the development of an investment agenda through the European Clean Hydrogen Alliance to propel hydrogen production and utilization projects. Additionally, strategic investments in clean hydrogen will be supported as part of the

Commission's recovery plan, particularly through the Strategic European Investment Window of InvestEU, starting from 2021. (European Comission, 2020)

On the international front, a pivotal action involves establishing a collaborative framework for renewable hydrogen cooperation with the African Union within the Africa-Europe Green Energy Initiative. This underscores the commitment to fostering global partnerships and leveraging Africa's abundant renewable energy resources to further advance the sustainable energy transition. (European Comission, 2020)

2.1 Renewable Fuels Compliance and Target Requirements

The "Fit for 55" initiative, approved by the European Commission in July 2021, is designed to harmonize current climate and energy regulations with the EU's objective of cutting greenhouse gas emissions by at least 55% by 2030, as part of the broader European Green Deal targeting climate neutrality by 2050. A key component of this package is the revision of the Renewable Energy Directive (RED II), with subsequent increases in renewable energy targets to support the achievement of the 55% GHG reduction goal, culminating in the adoption of RED III in November 2023. (European Parliament, 2023). Fit for 55 sets targets for 2030 including a 29% share of renewable energy sources or a 14.5% reduction in GHG emissions in the energy sector, with specific subtargets for various transport sectors, such as a minimum of 5.5% for advanced biofuels and RFNBO, including a 1% minimum for RFNBO, and varying caps for food and feed-based biofuels and waste biofuels, along with energy content multipliers for aviation and shipping (European Parliament, 2023). The minimum targets for RFNBO ensure a consistent portion of RFNBO in the market and encourage demand for these fuels. Double counting and multipliers help reduce the cost difference between RFNBO and crop-based biofuels, making RFNBO economically competitive and attractive.

Member states are obliged to achieve their targets for renewable hydrogen, which is referred to as RFNBO, derived from renewable energy sources. Certified RFNBOs receive incentives, with requirement for a minimum of 70% greenhouse gas savings compared to a fossil reference value of 94gCO2e/MJ (Hydrogen Europe, 2023).

The revision of RED expanded RFNBO to encompass sectors beyond transport, extending its application to include liquid and gaseous fuels utilized in the electricity sector, non-energy applications within the industrial sector, and the heating and cooling sector (European Parliament, 2023).

Directive 2023/2413, commonly known as RED III, has introduced new industry targets such as an annual increase of at least 1.6% in renewable energy usage within the industry. Additionally, the directive aims for 42% of hydrogen to be derived from RFNBO by 2030, and 60% by 2035 (Official Journal of the European Union, 2023).

The Renewable Energy Directive includes a definition of RFNBO, encompassing hydrogen produced through electrolysis from renewable electricity and its derivatives. Renewable hydrogen, often simplistically referred to, must meet the RFNBO criteria outlined in the RED to qualify. Articles 25(2)(a) of the RED states that RFNBOs are counted towards transport targets also if used as intermediate products in the production of conventional transport fuels and biofuels, such as in refinery processes and biodiesel production (Official Journal of the European Union, 2023). Producers holding RFNBO certificates can sell them, providing a financial incentive. As per Article 6 of the RFNBO Directive, the price for emitting 1 tonne of carbon dioxide equivalent must align with the previous day's closing price for December futures of the ongoing year, sourced from Intercontinental Exchange (ICE) Index or European Energy Exchange (EEX) (European Commission, 2024).

2.1.1 Additionality Requirement

Additionality in the context of RFNBO production stipulates that renewable energy sources used must be from assets that would not exist without the RFNBO production. This criterion includes conditions such as the installation of renewable energy that comes into operation no later than 36 months before the electrolyzer and does not receive public financial support. A transitional phase is outlined for installations operating before the end of 2027, with additionality requirements effective from January 1, 2038, while exemptions exist for certain scenarios, such as locations with high renewable energy shares or low emission intensities. The rationale behind strict additionality requirement is to prevent RFNBO production from diverting existing

renewable electricity away from the market, potentially leading to increased greenhouse gas emissions. Despite its importance in maintaining environmental integrity, the introduction of additionality requirements may pose challenges for RFNBO producers, particularly in industries where significant renewable hydrogen demand exists (Hydrogen Europe, 2023).

The strict rules about where the electricity used to make RFNBOs comes from can make it harder for RFNBO production in the EU to compete with imports. The European Commission's assessment shows that under these strict rules, there would be no RFNBO production in the EU that could compete in terms of cost with imports from other countries. So, the strict rules essentially make it too expensive for EU-based RFNBO production to be competitive in the EU market (European Commission, 2022).

The RFNBO delegated act provides two exemptions to the additionality requirement. The first exemption is in case of high renewable energy share in the grid. The additionality requirement is waived if the electrolyzer is located in a bidding zone where more than 90% of electricity comes from renewable sources. In such regions, including Portugal and Austria, where the renewable energy share is nearly 100% and grid emissions are below the threshold, producers can directly use grid electricity for hydrogen production without additional criteria (Hydrogen Europe, 2023, p.5).

The second exemption is related to low emission intensity. The additionality requirement is also not needed if the RFNBO installation is in a bidding zone with an electricity emission intensity below 18 gCO2eq/MJ, as described in Article 27.3 of the Renewable Energy Directive (RED). This condition allows producers to bypass further requirements like temporal and geographical correlation (Hydrogen Europe, 2023, p.6).

While these exemptions ease regulatory requirements, achieving a 70% GHG reduction remains challenging for most Member States due to higher grid GHG intensities or low RFNBO output. RFNBOs must meet a maximum GHG emission intensity of 28.2 gCO2e/MJ (Hydrogen Europe, 2023, p.3).

In the short term, developing new renewable energy sources takes many years, so there is not enough "additional" renewable energy available for hydrogen producers to

realistically use immediately. Therefore, hydrogen producers must buy renewable energy from the market to operate. Currently, there is no dedicated infrastructure for pure hydrogen transmission, so until natural gas pipelines are converted for hydrogen use, electrolyzers must rely on the electricity grid for power (Hydrogen Europe, 2021, p.6).

In the long term, hydrogen production will increasingly use new renewable energy sources because it would be the cheapest form of electricity. Since electricity costs make up about 70-80% of hydrogen production costs, it would be more economical for hydrogen producers to connect electrolyzers to these new, cheaper renewables (Hydrogen Europe, 2021, p.6). After 2030, a hydrogen network with both new and repurposed pipelines will develop, enabling cheaper hydrogen transport compared to electric cables. It is 10-20 times cheaper to move energy as hydrogen than as electricity. This will encourage placing electrolyzers closer to renewable energy sources, reducing electricity transmission costs. This shift will support faster and wider integration of renewable energy across the entire energy system, alongside increased electrification (Hydrogen Europe, 2021, p.7).

2.1.2 Temporal Correlation Requirement

The temporal correlation requirement imposed by Renewable Energy Directive II into the RFNBO Directive mandates that the electricity used in producing RFNBOs should match the timing of the electricity produced by the renewable energy unit specified in a renewables PPA (Hydrogen Europe, 2023). If a company has an agreement to buy renewable electricity from a specific source, the electricity used to produce RFNBOs should come at the same time that the specified renewable energy unit is generating power. This ensures that the renewable electricity used in RFNBO production is directly tied to the renewable energy source agreed upon in the PPA. The primary reason for ensuring temporal correlation between renewable electricity and RFNBO production is to maintain compliance with the RED II. If there is a mismatch in timing between the renewable electricity and RFNBO production, it is possible that the RFNBO production process might end up using non-renewable electricity. This would go against the requirement of RED II, which mandates that electricity used in RFNBO

production must be exclusively from renewable sources. Additionally, RFNBO technologies are designed to be a key component of fully renewable energy systems. They are expected to help integrate intermittent renewable electricity production by serving as a flexible load that aligns with the availability of renewable energy. In other words, RFNBO production should be able to adjust its electricity consumption based on when renewable energy is being generated, which enhances the overall efficiency and reliability of renewable energy systems. (Hydrogen Europe, 2023)

However, despite these motivations, there are concerns about how the requirement for temporal correlation is being implemented. The issue lies in the fact that if a temporal correlation between the electricity used in RFNBO production and the renewable energy source specified in the PPA cannot be demonstrated, the emissions associated with that electricity are fully counted against the RFNBO production. On the other hand, no credit is given for any GHG emission reduction achieved when surplus renewable electricity is exported to the grid. This discrepancy is seen as unfair and could negatively impact the production of RFNBOs (Hydrogen Europe, 2023).

To illustrate the challenge posed by strict hourly temporal correlation, a scenario should be considered involving a refinery requiring a constant supply of hydrogen throughout the year, with minimal downtime for maintenance. In case of green hydrogen production, an electrolyzer operator is tasked with producing hydrogen for the refinery. A PPA is secured with a solar PV plant to meet the energy needs. In the RED, a renewable PPA is a contract where a person or entity agrees to buy renewable electricity directly from a producer. Fuel producers under the directive can arrange renewable PPAs directly or through intermediaries. These agreements must clearly identify the renewable electricity sources used to produce renewable hydrogen (European Commission, 2024). Throughout the day, the electrolyzer would predominantly be powered by the solar PV plant's output, with any surplus renewable energy being exported to the grid. During nighttime, when solar energy is not available, the electrolyzer would draw electricity from the grid. However, any grid electricity consumed must not exceed the surplus renewable energy exported earlier in the day. Importantly, utilizing grid electricity at night could potentially increase GHG emissions by requiring additional energy from less sustainable sources. Conversely, exporting excess renewable energy during the day displaces other energy sources,

leading to GHG emission reductions. The overall GHG balance heavily relies on the renewable energy mix, with potential challenges arising in regions where solar energy predominates during high-demand periods and grid electricity, mainly sourced at night, is derived from wind energy or faces renewable energy curtailment. It is important to note, that strict hourly temporal correlation disregards the environmental benefits of exporting surplus renewable electricity to the grid while imposing the full burden of GHG emissions on RFNBO production.

RFNBO producers could consider innovation and explore a hybrid approach, combining solar, wind, and other renewable sources while incorporating storage solutions. This would help ensure a better match between the availability of renewable energy and the operation of the electrolyzer.

2.1.3 Geographical Correlation

The RED II states that for grid electricity used in RFNBO production to be considered renewable, there must be a "geographical correlation" between the renewable electricity producer and the fuel producer with a bilateral renewables PPA (Official Journal of the European Union, 2023). The renewable energy source and the electrolyzer must be in the same bidding zone, or the renewable energy source is in a connected bidding zone, and if it is not offshore, and the day-ahead market prices for the relevant period were higher than in the bidding zone where the electrolyzer is located (Hydrogen Europe, 2023, p.14).

2.2 Austria's Hydrogen Strategy

The Austrian Federal Government has recognized the urgency of the climate change and has established an ambitious target: attaining climate neutrality in Austria by 2040. This vision entails a comprehensive energy transition characterized by a significant reduction in energy consumption and a sustainable energy supply based on renewable sources (IEA, 2020).

At present, hydrogen is used extensively in various industrial applications, particularly as a chemical feedstock. However, nearly all the hydrogen consumed is produced using CO2-intensive processes from fossil sources, mainly natural gas. As Austria continues to transform its industrial sector and decarbonize its transport sector, the demand for renewable hydrogen is expected to increase substantially. This transformation will likely result in numerous new energy-intensive applications that drive a significant rise in hydrogen demand (Federal Ministry Republic of Austria, 2022). Examining the Austrian Hydrogen strategy provides valuable insights into how individual nations are aligning their policies and initiatives with broader regional and global efforts towards sustainable energy transformation. Austria aims to achieve a significant milestone by substituting 80% of fossil-based hydrogen with climate-neutral hydrogen in energy-intensive sectors by 2030. This ambitious goal is part of the Hydrogen strategy, which also includes the installation of 1GW electrolyzer capacity by 2030. Additionally, the broader objective is to attain climate neutrality by 2040. (Federal Ministry Republic of Austria, 2022). Equally essential are the development of a targeted infrastructure and the international partnerships for climate-neutral hydrogen. (Federal Ministry Republic of Austria, 2022)

For the future Austria set goals to shift this grey hydrogen to green hydrogen to replace it. Current demand will remain in the industry application, but it will be replacement from grey to green and this is ongoing process at OMV. 132 000 tonnes of hydrogen are consumed yearly in Austria which corresponds to close to 5.7 TWh per year (Klima Energie Fonds, Federal Ministry Republic of Austria, 2023). To shift from grey to green hydrogen means that the required electrolyzer capacity should be around 830MW to cope with this demand. Where we stand today from this 830MW, 13MW are installed with several different pilot projects ongoing in Austria, around 12MW are in errection, especially new facility directly at the refinery of OMV (Klima Energie Fonds, Federal Ministry Republic of Austria, 2023). In a renewable energy system, hydrogen can play a crucial role through Power-to-Gas technologies. These technologies enable the production of renewable hydrogen using renewable electricity, thus acting as a bridging element between the electricity sector and a future fossil-free gas sector. Power-to-Gas technologies allow for the long-term and seasonal storage of energy and the decarbonization of applications that cannot be electrified (Federal Ministry Republic of Austria, 2022).

3 Advancements in Hydrogen: Production, Transportation and Utilization

3.1 Production of Hydrogen

Hydrogen is the most common element in the universe, more than 90% of atoms are hydrogen. This atomic form cannot be found because hydrogen is very reactive. It immediately reacts with other elements especially with carbon and other hydrogen atoms as well. On earth is can be mainly found in combination with other elements as methane or hydrogen in molecular form (Sema, 2018) .

Figure 1 shows different methods and types for producing hydrogen:

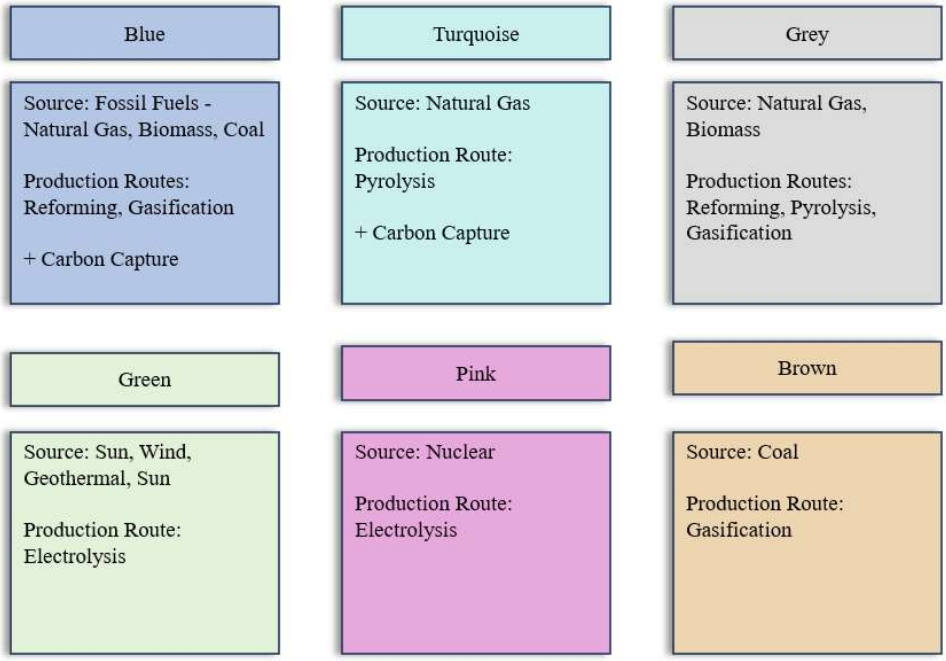


Figure 1 - Types of hydrogen and methods of production (derived from Ayub et al. (2024) and IEA (2021)

Steam methane reforming is often regarded as the most commercially viable mean of hydrogen production, with efficiency of around 70% (Sema, 2018). Hydrogen derived from fossil resources is typically termed “grey hydrogen” (Ayub et al., 2024).

The future lies in focus of renewable energy carriers especially in fluctuating energy carriers like solar and wind and this renewable electricity will be mainly used in electrolysis to split water into hydrogen and oxygen (Deloitte, 2023; IEA, 2019a). Hydrogen generated in this way is referred to as "green hydrogen" (Ayub et al., 2024). The efficiencies for the total process range from 60 to 80% (IEA, 2019a, p.43). The current operating pressures for alkaline electrolyzers range from 1 to 30 bar, whereas Polymer Electrolyte Membrane (PEM), it is 30-80 bar (IEA, 2019a, p.44). Given the dependency of green hydrogen generation on energy sources like the sun and wind, these conditions significantly influence production costs (Deloitte, 2023).

Presently, the primary method for producing hydrogen on a global scale is through steam methane reforming (SMR) using natural gas, which constitutes approximately 76% of the total dedicated hydrogen production of around 70 million metric tons per year (IEA, 2019a, p.37). Blue hydrogen is produced similarly to grey hydrogen, but with the added step of carbon capture and storage to reduce carbon emissions (Oliviera et al., 2021). The cost of producing blue hydrogen is heavily dependent on gas prices (IEA 2023a, p. 87). Unlike blue hydrogen, the cost of green hydrogen is not directly linked to natural gas prices, offering a shield against the recent price volatility seen in Europe and Asia (Deloitte, 2023, p.44). Turquoise hydrogen is derived from a hydrocarbon feedstock such as natural gas and uses pyrolysis to create solid carbon particles than fully converting the carbon into CO2 (Ayub et al., 2024, p.923). Nuclear power can serve as an alternative source for hydrogen production. Despite a nuclear power plant's absence of direct emissions, the overall nuclear fuel cycle, involving processes like uranium mining, conversion, enrichment, and fuel fabrication, leads to emissions ranging from 2.4 to 6.8 grams of CO2-equivalents per kilowatt-hour (IEA 2023a, p.88). Pink hydrogen is produced using electrolysis powered by nuclear energy sources (Ayub et al., 2024). Brown hydrogen is produced from fossil fuels, particularly coal (IEA, 2021).

The upcoming sections explore hydrogen production methods, with emphasis on Steam Methane Reforming and Electrolysis. SMR is a prevalent method used in refineries for hydrogen production, and this thesis further explores the transitioning to the production of green hydrogen as an alternative to SMR.

3.1.1 Steam Methane Reforming

Currently in the Schwechat refinery hydrogen is produced via steam reforming using natural gas. Hydrogen production via steam methane reforming takes place in a reformer, where hydrocarbons react with steam at high temperatures. This industrial process, which began in the 1930s, became the most cost-effective method of hydrogen production by the 1960s (Rostrup-Nielsen, 2004). Operating at temperatures between 700-900°C and using nickel as a catalyst, methane reacts with steam to produce carbon monoxide (CO) and hydrogen (H2), achieving approximately 70% efficiency (Vogt et al., 2020). The process involves two key reactions: the first is an endothermic reaction that converts methane and steam into a mixture of CO and H2 (Kazunari et al., 2015, p.128):

$$CH_4 + H_2O \rightarrow CO + 3H_2$$

The second reaction is a lower temperature gas-shift reaction that further extracts hydrogen from the CO (Kazunari et al., 2015, p.128):

$$CO + H_2O \rightarrow CO_2 + H2$$

Steam methane reforming contributes significantly to global CO2 emissions (IEA, 2023a).

3.1.2 Electrolysis and Types of Electrolyzers

Water electrolyzers use electricity to split water into hydrogen and oxygen, converting electrical energy into chemical energy (Cavaliere et al., 2021, p.26)

An electrolytic cell drives chemical reactions through electrical energy. Core components are electrolyte, anode, cathode and power supply (Luz, 2017, p.34). Each electrolyzer comprises two electrodes and an electrolyte, with multiple cells forming a stack for increased hydrogen production. Key subsystems include cooling, hydrogen purification, and water supply, known collectively as the balance of plant (BoP) (Singh et al., 2024). Electrolyte is commonly a solution of water and a salt (like sodium chloride (NaCl)), acid (like hydrochloric (HCl)) or base (a hydroxide like NaOH). Anode is the positive electrode where oxidation occurs and oxygen gas is foremd (Luz,

2017). Electrolyzers use this process specifically to produce hydrogen and oxygen from water with different types of electrolyzers designed for different efficiencies and applications.

3.1.2.1 Alkaline Electrolyzers

Alkaline electrolyzers take up a large portion of the commercial electrolyzer market. (Zini Gabriele, 2011). It is a well-established technology dating back to the 1920s, was primarily used for hydrogen production in industries like fertilizers and chlorine. Despite its decline in usage post-1970s due to the rise of natural gas and steam methane reforming, alkaline electrolyzers are known for their cost-effectiveness and avoidance of precious materials like platinum and iridium (IEA, 2019). Regions with stable baseload power sources like hydro, nuclear, or coal find alkaline electrolyzers suitable for their continuous electricity supply needs, making them a preferred choice for cost-efficient and reliable hydrogen generation (Song et al., 2024).

Figure 2 demonstrates the how the alkaline electrolyzer operates. In an AE, a 25-30% potassium hydroxide (KOH) or sodium hydroxide (NaOH) solution is used as the electrolyte. Key components include nickel-based electrodes and a microporous diaphragm. Water decomposes at the cathode, forming hydrogen and hydroxyl ions (OH^-), which pass to the anode to produce oxygen. Hydrogen is separated outside the electrolyzer. AEs operate at 60-80°C with a current density of 0.2-0.4 A/cm² and an efficiency of 63-71% (Singh, 2024).

The reactions of AE (Singh et al., 2024):

Anode: $4OH^- \rightarrow 2H_2O + 4e^- + O_2$

Cathode: $4H_20 + 4e^- \rightarrow 4OH^- + 2H_2$

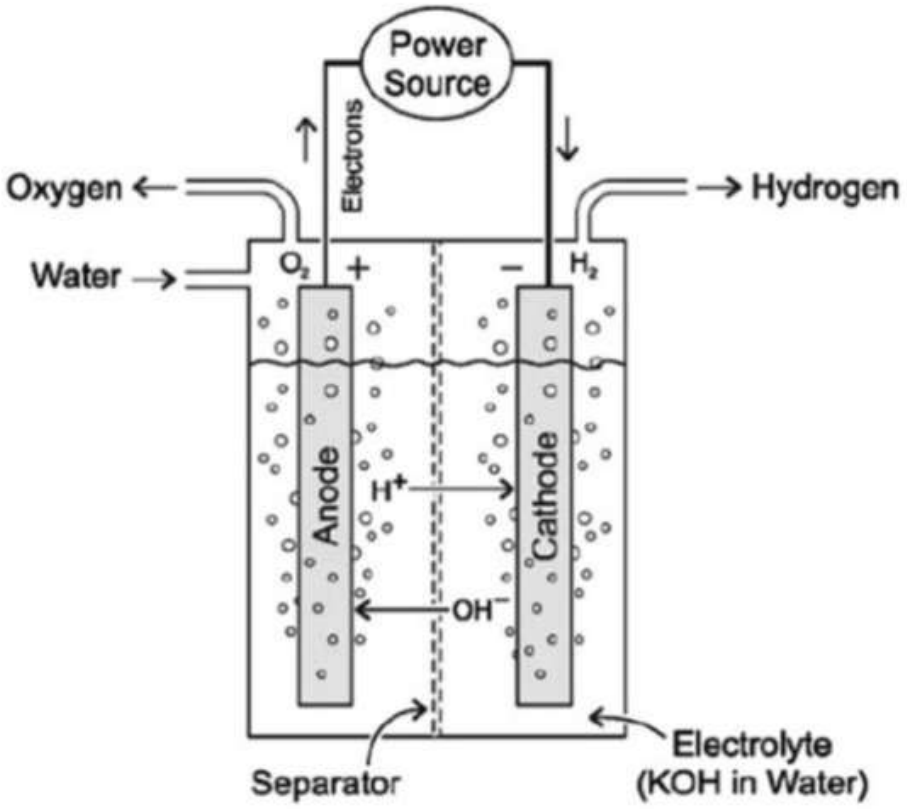


Figure 2 - Alkalyne electrolyzer scheme (Luz, 2017, p.37)

3.1.2.2 Proton Exchange Membrane Electrolyzer

PEM electrolyzer systems, introduced in the 1960s by General Electric, offer compact designs and the flexibility to produce highly compressed hydrogen for decentralized storage and usage. While they address some drawbacks of alkaline electrolyzers, such as eliminating the need for potassium hydroxide recovery, PEM systems face challenges related to higher costs due to the use of expensive electrode catalysts and membrane materials, limiting their widespread adoption (IEA, 2019).

Proton exchange membrane electrolyzers use a polymer electrolyte membrane (e.g., Nafion), instead of a liquid one like alkaline electrolyzers, to separate the electrodes, with catalysts like platinum, iridium, ruthenium, and rhodium. Water is introduced at the anode, where it splits into protons and oxygen. Protons move through the membrane to the cathode, where they form hydrogen gas. PEM achieve high current

densities and efficiencies of 56–60% due to low ionic resistance (Singh et al., 2024). They are known for operating efficiently at smaller scales, producing hydrogen at higher purity levels directly. PEM systems are suitable for applications where space is limited or hydrogen demand is low, and they can rapidly adjust to electricity supply changes, making them ideal for pairing with renewable energy sources like solar and wind (IEA, 2019). However, they face issues such as material corrosion, high costs of noble metal catalysts, and lower efficiency compared to other methods. Efforts are ongoing to improve their efficiency (Singh, 2024). In many projects using electrolysis technology, PEM electrolyzers are favored over alkaline ones. This preference may stem from the focus on testing environments suitable for newer technologies with the potential for cost reduction (IEA, 2019). Reactions of PEM (Singh, 2024):

Anode: $2H_2O \rightarrow 4H+ + 4e- + O_2$

Cathode: $4H+ + 4e- \rightarrow 2H2$

Overall: $2H_2O \rightarrow 2H_2 + O_2$

Figure 3 demonstrates the how the PEM electrolyzer operates.

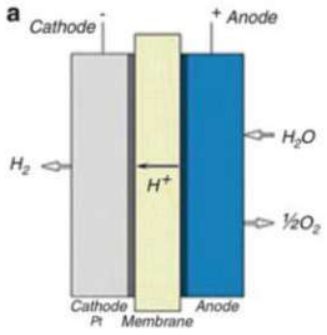


Figure 3 - PEM Electrolyzer operation (Luz, 2017, p.39)

3.1.2.3 Solid Oxide Electrolyzer

Solid oxide electrolysis cells (SOECs), considered the least matured electrolysis technology, utilize ceramics as the electrolyte and operate at high temperatures with high electrical efficiency (Yenesew et al., 2023). While not yet commercialized, SOECs hold the potential for various applications, including the production of

synthetic fuels through co-electrolysis of steam and carbon dioxide. Challenges for SOEC development include material degradation at high operating temperatures and the need for heat sources such as nuclear power, solar thermal, or geothermal systems for efficient operation (IEA, 2019). SOEC use yttria-stabilized zirconia (YSZ) as the electrolyte, with high operational temperatures (650–1000 °C) that combine electrical and thermal energy to split water (Singh, 2024). They achieve high electrical efficiency (85–90%), though overall efficiency decreases when including heat input. Advantages include non-corrosive solid electrolytes, and no flow distribution issues, but they are hindered by expensive materials, fabrication costs, and the need for a heat source. Figure 4 depicts the functioning of the SOEC electrolyzer. Although SOECs show high efficiency, they are still in the developmental stage (Singh, 2024):

Reactions of SOEC (Singh, 2024):

Anode: $O_2- \rightarrow 1/2O_2 + 2e-$

Cathode: $H_20 + 2e- \rightarrow H_2 + O_2-$

Overall: $2H_20 + \rightarrow 2H_2 + O2$

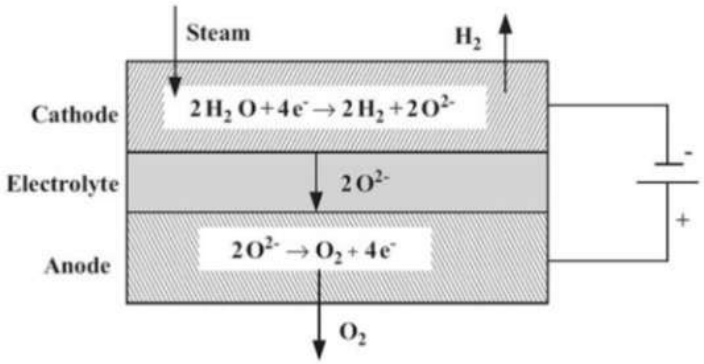


Figure 4 - Operation of a solid oxide electrolyzer (Luz, 2017, p.40)

Table 1 outlines key differences between the three mentioned types of electrolyzers.

Table 1 - Key differences between the three electrolyzer types (Sources IEA 2019, 2023c, IRENA 2021)

	Alkaline		PEM		SOEC		Source
	today	2030	today	2030	today	2030	
Electrical efficiency (%, LHV)	63-70	65-71	56-60	63-68	74-81	77-84	IEA, 2019a
Operating pressure (bar)	1-30		30-80		1		IEA, 2019a
Operating temperature (°C)	60-80		50-80		650-1000		IEA, 2019a
Stack lifetime (operating hours)	60 000 - 90 000	90 000 - 100 000	30 000 - 90 000	60 000 - 90 000	10 000 - 30 000	40 000 - 60 000	IEA, 2019a
Load range (%, relative to nominal load)	10 - 110		0 - 160		20 - 100		IEA, 2019a
Advantages	low capital costs; use cheaper and more aboundant catalyst material compared to PEM electrolyzers		use of pure water as an electrolyte avoiding the need for potassium or sodium hydroxide recovery; highly compressed hydrogen for decentralized storage and refueling stations; flexible operation, frequency reserve and grid services		ceramics as the electrolyte, lower material costs; operates at high temperature with high electrical efficiency; can be operated in reverse mode as a fuel cell; capable of co-electrolysis of steam and carbon dioxide to produce synthetic fuels		IEA, 2019a
Disadvantages	not as suitable for decentralized production due to size and infrastructure requirements,		requires expensive electrolyte catalysts like platinum and iridium; shorter lifespan compared to alkalyne electrolyzers;		still in development stage and not commercialized widely; requires a heat source, such as steam for efficient operation; challenge of material degradation due to high operating temperatures		IEA, 2019a
TRL	9		9		7		IEA, 2023c
capability to participate in day ahead & intraday optimization	some systems capable with the exeption of primary power markets		yes		yes		IRENA, 2021
capability to participate in balancing power markets	some systems capable with the exeption of primary power markets		yes		yes		IRENA, 2021

PEM offers several advantages over AE, such as full load range operation, shorter start-up times and faster production rate variations, and to minimize the energy losses, the PEM electrolysis is considered more suitable for the scope of this thesis (Buttler, 2018).

3.2 Transport of Hydrogen

There are different pathways for supplying hydrogen. One can differentiate between the supply of elementary hydrogen and supply of derivatives. In order to transport hydrogen efficiently over long distances density needs to be increased and this is done by conditioning (Lucas et al., 2024). Conditioned hydrogen refers to hydrogen that has undergone processes to enhance its volumetric energy density for efficient storage and transportation. This involves methods such as compressing gaseous hydrogen, storing it as liquid hydrogen, or bonding hydrogen with other molecules (Lucas et al., 2024, p.1188).

Figure 5 depicts a range of conditioning options available for hydrogen treatment before the energy carrier is transported.

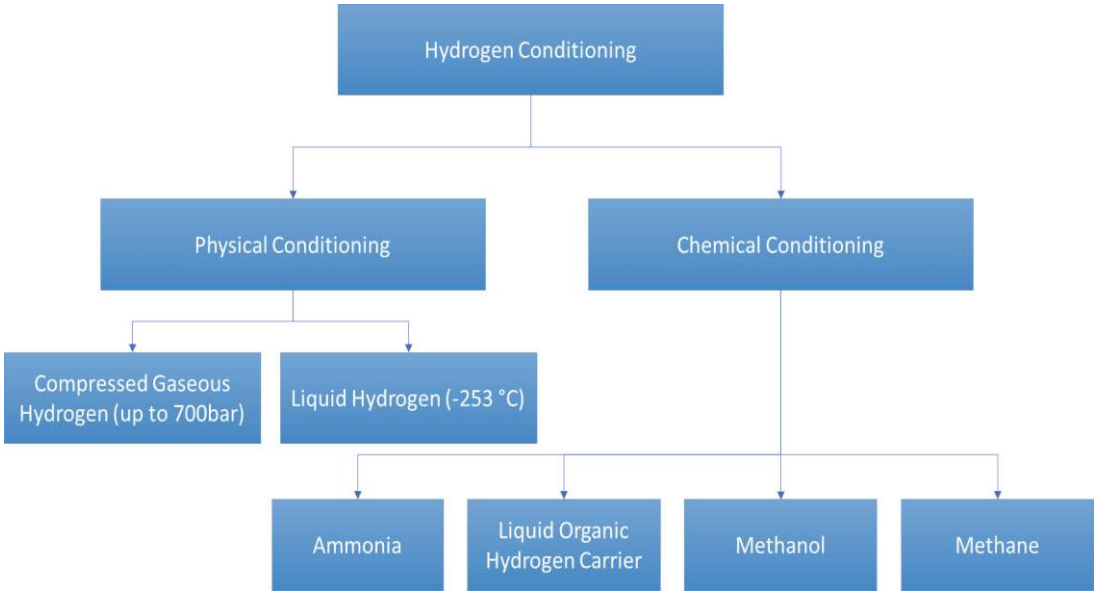


Figure 5 - Hydrogen Transport Options (own figure, derived from EHB (2021a), Sens et al. (2024), Moradi et al. (2019))

Most options for conditioning include carrier molecules such as nitrogen or CO2 (Lucas et al., 2024). After the conditioning energy carrier is transported. In this thesis, the option of using elementary compressed hydrogen is considered, which would be transported via gaseous pipelines directly to Austria. Hydrogen pipelines are the most cost-efficient method for long-distance, with the European Hydrogen Backbone (EHB) estimated to cost 0.11-0.21 EUR per kilogram per 1.000 kilometers, outperforming shipping for most distances (European Hydrogen Backbone, 2021a). Cost for hydrogen transport is considered to fall well below USD 1 per kg of hydrogen for large pipelines with capital expenditures being the primary expense. Refurbishing existing natural gas pipelines can reduce these capital costs by 65-94%. Studies in Europe have shown that repurposing a significant portion of existing pipelines is feasible (IRENA, 2022c). One drawback of repurposing pipelines is the potential need to operate them at a lower pressure to minimize the risk of crack propagation. This results in a reduced volume and energy transported, which in turn increases the cost per unit of hydrogen as well as compression costs (IRENA, 2022c, p. 113). Across Europe, 23 Transmission System Operators (TSOs) from 21 countries have projected

that the European hydrogen network could expand to 11 600 km by 2030 and further extend to 39 700 km by 2040. This would result in transport cost of 0.11-0.21 EUR/kg (IRENA, 2022c, p.110).

The IRENA provided cost components for pipeline transport based on the diameter of the pipeline as presented in Figure 6.

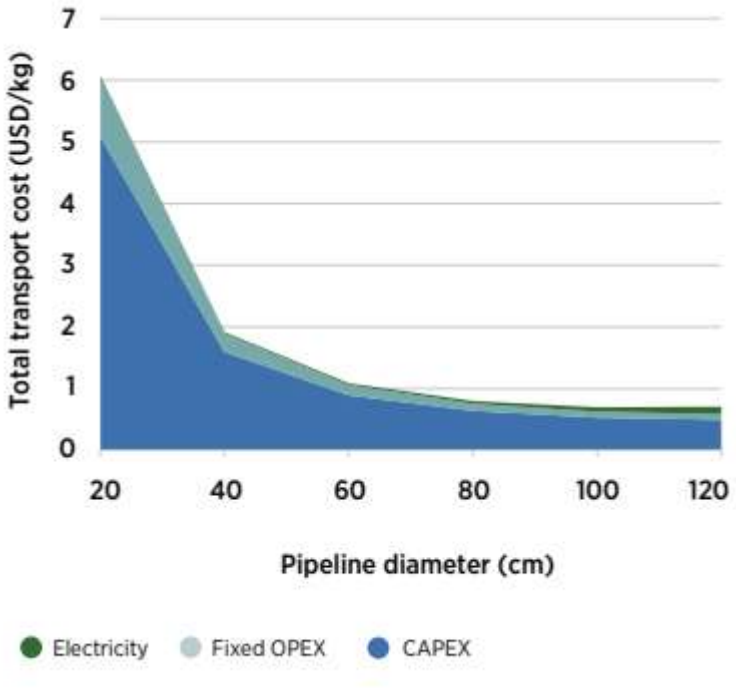


Figure 6 - Transport cost dependance on the Pipeline diameter (IRENA, 2022c, p.13)

The European Hydrogen Backbone (2021a, p.74) has identified three of the most promising options for hydrogen transport via ship, which this study examines: liquid hydrogen, liquid organic hydrogen carriers (LOHCs), and ammonia. For maritime transport, hydrogen gas must be either liquefied or transformed before it can be transported. This process incurs additional expenses that need to be considered alongside the costs of transporting and storing hydrogen, LOHC, or ammonia (IEA, 2019a, p.78)

And today the compressing technology is state of the art technology for using hydrogen. It means hydrogen is in a gaseous phase, in a pipeline is at pressure level of 80 bars and later on at 900 bar pressure in the vehicles (European Hydrogen Backbone, 2021b; (Genovese M., 2023)). In addition to a gaseous usage, hydrogen can be

liquified, then we are at temperature of -250 °C, very low and in this liquid form is also distributed and used as a fuel for space propulsion and also used in special applications like semi-conductor industry where the high purity is needed (Genovese M., 2023).

Liquified hydrogen can be transported via liquid hydrogen tankers, ships comparable to today's natural gas carriers (liquefied natural gas (LNG) carriers). LOHCs are carriers that use unsaturated organic compounds to store hydrogen. For instance, toluene can be hydrogenated to form methylcyclohexane, which can then be dehydrogenated back to toluene for reuse (Sun et al., 2023). Since LOHC is a component of gasoline, it can be transported via existing infrastructure such as chemical and oil tankers. The process involves binding hydrogen to a carrier molecule through hydrogenation for easy transport, and after dehydrogenation at the destination, the carrier molecule must be transported back (Kazunari et al., 2015). Similar supply chain is based on ammonia, here the carrier substant is not needed, this can be done by air separation and then go via Haber Bosch synthesis which is established process (El-Shafie et al., 2023, p-11238). Ammonia is liquified and then transported via the carrier and can be used directly. Ammonia can be conveniently stored and transported under moderate pressure using simple inexpensive vessel (El-Shaiffe et al., 2023). However, the process of converting ammonia back into nitrogen and hydrogen is inefficient and has not yet been demonstrated effectively on a large scale (European Hydrogen Backbone, 2021a, p.74). In Figure 7, a cost comparison for various hydrogen transport options from North Africa is provided by the EHB (2021a, p.78).

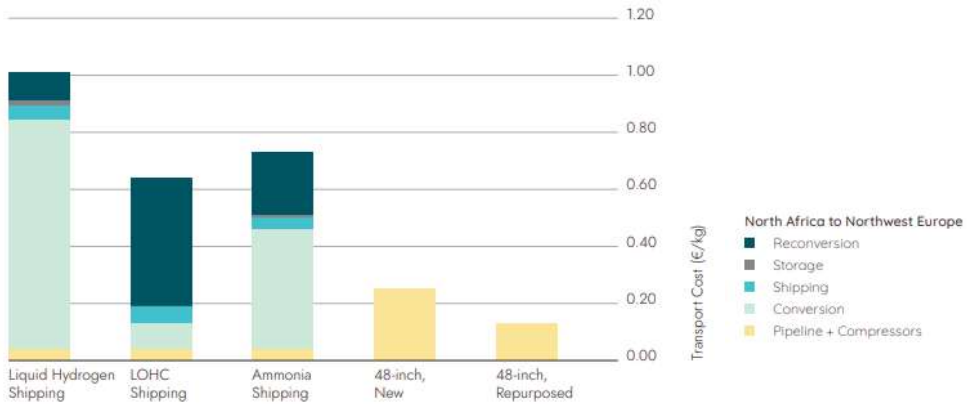


Figure 7 - Transport comparison from North Africa to Europe (EHB, 2021a, p.78)

3.2.1 Technological and Infrastructure Considerations

Hydrogen is most efficiently used in its pure form, necessitating dedicated transport methods or on-site production of climate-neutral hydrogen. The gas infrastructure must progressively become hydrogen-compatible to facilitate the transition of selected gas networks into a dedicated hydrogen infrastructure by 2040 (Federal Ministry Republic of Austria, 2022).

The primary strategy for pipeline transport involves converting existing natural gas pipelines to hydrogen pipelines, with the construction of new hydrogen pipelines considered where necessary. This strategy emphasizes integration into a broader European infrastructure. The potential for repurposing the current gas infrastructure is being evaluated within a hydrogen infrastructure roadmap and Austria's integrated network infrastructure plan (Federal Ministry Republic of Austria, 2022). When designing or repurposing pipeline networks, it must be noted that hydrogen's reactivity and potential to cause embrittlement in bare steel at high pressures necessitates the inclusion of oxide layers to prevent direct contact between hydrogen and steel (European Hydrogen Backbone, 2021a, p.71). In addition to ensuring the compatibility, another challenge is the higher energy required for compression (IRENA, 2022c, p.101).

Austria aims to build strong international partnerships for climate-neutral hydrogen. This includes strategic collaboration with potential trading partners and ensuring compatibility with international climate goals. The focus is on long-term supply security, cost-effective import routes, and reducing market barriers. On the EU level, the goal is to create transnational hydrogen networks and diversify energy imports, enhancing Austria's supply security and economic competitiveness (Federal Ministry Republic of Austria, 2022). Austria's potential to import hydrogen could be realized through the SoutH2 Corridor project, a dedicated hydrogen pipeline network spanning approximately 3 000 km that connects North Africa with Italy, Austria. The corridor aims to supply low-cost renewable hydrogen to European demand centers while utilizing over 70% repurposed pipelines for cost-effective transportation. With a hydrogen import capacity of 4 Mt per year, this project is essential for achieving

Europe's renewable energy targets and is expected to be operational by 2030, enabling a reliable flow of renewable hydrogen to Austria (SoutH2 – The initiative, 2024).

3.3 Use of hydrogen

Hydrogen can be utilized for a variety of industrial, residential and transport purposes, as summarized in Figure 8 derived from the Department of Energy (DOE, 2019). Climate-neutral hydrogen is a highly valuable energy carrier with significant potential for technical applications. It should be primarily directed towards sectors that are particularly challenging to decarbonize and where alternative methods, such as electrification, are not feasible (Deloitte, 2023). These sectors include material and energy applications in energy-intensive industries, specific areas within the mobility sector that are difficult to electrify, the refining industry, and the production of aviation fuels and chemicals. In these challenging-to-decarbonize sectors, green hydrogen presents an excellent solution (Deloitte, 2023).

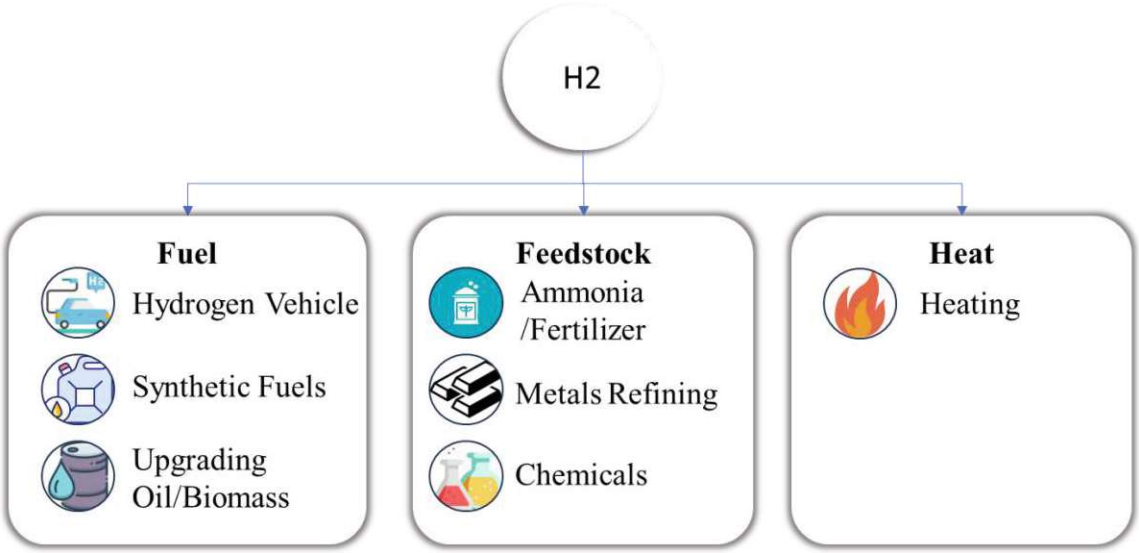


Figure 8 - Hydrogen application (own figure, derived from: DOE Hydrogen and Fuel Cells Program, 2019, p.2)

The oil refining sector is the largest producer and consumer of hydrogen in the EU (Fuel Cell and Hydrogen Observatory, 2021, p.7). In the refining sector, hydrogen consumption exceeded 41 million tonnes in 2022, accounting for 43% of the global hydrogen demand (IEA, 2023a).

All major EU refineries produce hydrogen from fossil fuels, primarily natural gas, using several methods: reforming operations for hydrotreating, steam reforming or autothermal reforming of light ends or natural gas and partial oxidation (gasification) of heavy oil fractions. While simpler refineries may generate sufficient hydrogen through catalytic reforming alone, more complex facilities with extensive hydrotreating and hydrocracking processes usually require additional hydrogen beyond what their catalytic reforming units produce (Fuel Cell and Hydrogen Observatory, 2021, p.7).

4 Green Hydrogen Production: Background and Assumption

4.1 Green Hydrogen Production in Austria

The goal in Austria is to get close to 1GW in 2030 with green hydrogen production (Federal Ministry Republic of Austria, 2022). This highlights the necessity for the expansion of renewable energy sources, such as solar, wind and hydropower. Ideally, harnessing this green electricity and efficiently distributing it across various sectors including energy, mobility, and industry via the grid and energy storage would be optimal. However, Austria faces challenges due to limited solar hours (1000 hours/year), water (4000-5000 hours/year), and wind power availability (2500 hours/year) (E-Control, 2021). This temporal gap poses a significant challenge, particularly for sectors with continuous energy demands like refineries.

Addressing temporal energy balance complexities and meeting mentioned RED requirements, this thesis focuses on wind and solar investments to achieve a sustainable and reliable electricity supply for an electrolyzer in Austria.

4.1.2 Required Electrolyzer Capacity

To determine the appropriate size for an electrolyzer, considered are several key factors, beginning with projected green hydrogen demand for Schwechat refinery units for 2030, which is approximately 11 700 tonnes per year. While providing the data on hydrogen demand, it is important to recognize that these estimations are influenced by several key factors. The demand for hydrogen in refineries takes into account factors such as refining capacity, the amount of sulfur required for the purity of crude oil that depends on data on crude oil sources, permitted sulphur levels in the product (DOE Hydrogen and Fuel Cells Program, 2019, p.3).

However, the electricity potential of a chosen area has to be taken into account, as well as the European Union's goal to source 50% of its hydrogen through imports and 50% from local production. Given these considerations and taking into account that one half of the refinery's demand would be covered through imports and another through the local production, decided is to set target capacity for the new electrolyzer at 5 833

tonnes of hydrogen per year. This balance aligns with both the local electricity potential and the strategic objectives outlined by the EU, to contribute to local hydrogen production but as well to adhere to import targets.

The electricity consumption by the electrolyzer-based hydrogen generation system can be determined using the formula from Alfredo (2012):

$$E = \frac{p * HV}{\eta_E} \qquad [kWh/year] \qquad (1)$$

With:

E … Electricity requirement (kWh/year)

p … rated hydrogen production capacity of the electrolyzer (kg/year)

HV… Heating value (kWh/kg)

η_E… efficiency of the electrolyzer (%)

By applying the Equation 1 and considering the heating value of hydrogen is 39.4 kWh, along with the efficiency of a conventional electrolyzer at 70%, it translates to 56.3 kWh of electricity needed per kilogram of hydrogen produced (Nicita et al., 2020, p. 11401). This equates to an estimated 328 GWh/year of electricity required for the total yearly hydrogen output. Table 2 summarized the data on the hydrogen output and the electricity required.

Table 2 - Electrolyzer plant characteristics

Table	Electrolyzer Plant Characteristics		
Parameter	**Value**	**Unit**	**Note (Source)**
Electricity Required	328 333 333	kWh/year	calculated
Efficiency of the electrolyzer	70	%	Deloitte 2023; Nicita et al, 2020
Plant Lifetime	20	years	Nicita et al, 2020
Hydrogen Output	5 833 333,33	kg/year	Internal projections of hydrogen demand for refinery processes (OMV data)
Electrolyzer type	PEM		
Electrolyzer Full Load Hours	8 500	hours/year	Achievable FLH by installing additional stacks and using PEM technology (discussions with experts from OMV)

4.1.3 Supplying Electrolyzer with Electricity from the Grid

As mentioned in Chapter 2, the Delegated act is important to define the electricity sourcing strategy for green hydrogen production, which can be classified as RFNBO and counted toward the quota fulfillment. Electricity purchases via the public electricity grid are generally permissible for the production of RFNBO hydrogen. The

proportionate share of renewable electricity in the public electricity grid in Austria is restrictive, as only this may be used for RFNBO hydrogen production. With the remaining electricity share, only a so-called "low-carbon" hydrogen can be produced, but no RFNBO hydrogen. The share of renewable energies in gross electricity consumption in Austria in 2022 was 74.7% (Eurostat, 2023). In accordance with the Austrian political target for the expansion of renewable electricity production by 2030, the share is to grow to 100 percent (IEA, 2020). In addition to the renewable electricity share, the absolute greenhouse gas emissions of the Austria's electricity mix must also be taken into account in the calculation of the global warming potential of RFNBO hydrogen. In 2020, the greenhouse gas intensity of the electricity mix in Austria was 51 g CO2eq/MJ (Hydrogen Europe, 2023, p. 4).

Given that Austria is close to and aims to have a 100% renewable electricity grid by 2030 and since the electrolyzer producing hydrogen for a refinery needs to operate continuously, any shortfall of renewable electricity in the case of local green hydrogen production in Austria will be compensated by drawing electricity from the grid. This approach ensures that the electrolyzer can maintain consistent operation while aligning with requirements of the Delegated act. For this thesis, approximately 50% of the electricity is sourced from invested wind and solar PV power plants, while the remaining 50% is obtained from the grid. By implementing this strategy, the electrolyzer can operate consistently and remain compliant with regulatory mandates.

4.1.4 Solar and Wind Energy Potential

In this scenario, investments into power plants in Lower Austria, Bruck and der Leitha are considered. The premise is that the installed capacities of PV and wind park align with the capacity of the electrolyzer unit. This setup eliminates the possibility to sell excess electricity to the grid, therefore, role of the grid would be only as a balancing agent.

Lower Austria and Bruck an der Leitha location is chosen for the electrolyzer due to the presence of a substation and its electrical capacity and proximity to the refinery, coupled with robust infrastructure capabilities. The presence of the substation nearby further enhances the suitability of this site, as it enables a reliable connection to the

grid, thereby ensuring a steady and sufficient power supply for the electrolyzer's operations.

Given that the refinery's demand for hydrogen remains constant and continuous throughout the year, the methodology involves analyzing hourly electricity profiles from wind and solar power plants. To address any shortfalls in supply, additional electricity would be procured from the grid. Therefore, to supply the refinery, it is calculated how much electricity is needed and how much the PV and wind power plants could produce. The full capacity of the electrolyzer is not covered exclusively by solar and wind power plants. Furthermore, due to the temporal correlation requirement for RFNBO, it is necessary to analyze these hourly profiles in detail.

4.1.4.1 Solar Energy Potential Lower Austria

For the simulation and calculation of annual PV energy yields, data from the Photovoltaic Geographical Information System (PVGIS) and the Global Solar Atlas is analyzed. PVGIS and Global Solar Atlas are tools used to calculate PV energy yield for a chosen location.

The performance ratio (PR) is a crucial measure for evaluating the efficiency of a PV plant, representing the ratio of actual energy output to the theoretically possible output. It is independent of location and can be used to compare PV plants worldwide. The PR reflects the quality of a PV plant, indicating the proportion of energy available for export after deducting losses (thermal and conduction) and consumption. Although a value of 100% is not attainable due to inherent losses, high-performance PV plants can achieve a PR of up to 80%. A minimum analysis period of 1 month is recommended to mitigate the impact of environmental conditions on the calculation. PR accounts for various factors such as system losses, soiling, shading, temperature effects, and other environmental conditions. (SMA Solar Technology AG)

For designing and implementing PV system it is very important to calculate sun radiation potentials for the location. The yearly sunlight exposure data for the chosen location Bruck an der Leitha was in the first step obtained from the PVGIS database. PVGIS is a comprehensive tool that maps solar energy potential and evaluates

electricity generation from solar panels across Europe, Africa, and South-West Asia. The Figure 9 shows the solar radiation results calculated for the Bruck an der Leitha location using PVGIS tool. With an optimal inclination angle of 34 degrees the average daily irradiation on an annual basis according to the database is 1500.85 kWh/m²/year.

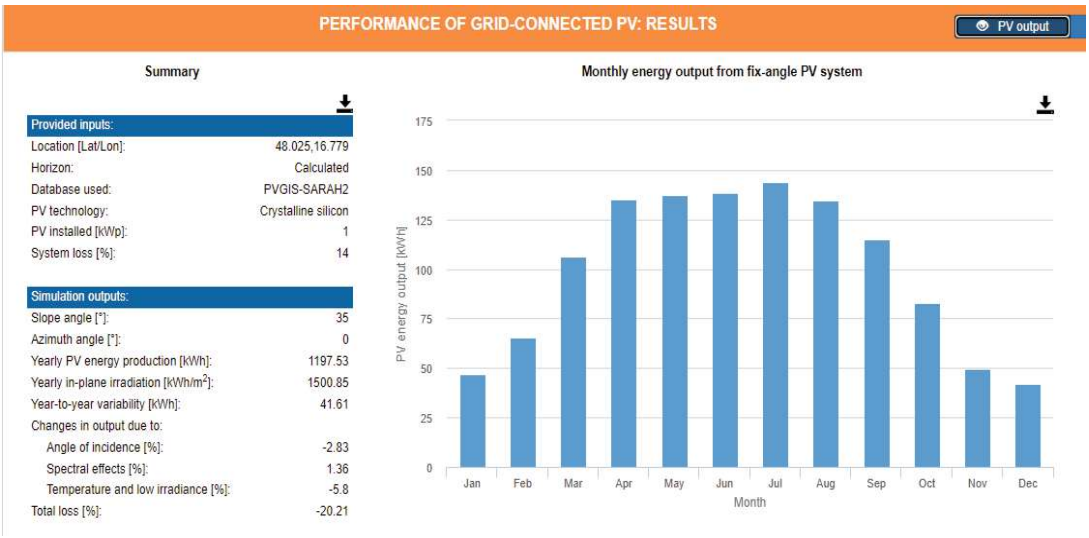


Figure 9 - Calculation of radiation result (PVGIS 2024, https://pvgis.com)

Further results from PVGIS in Figure 10 demonstrate the total yearly energy production of 43.7GWh for a 40MW PV plant.

PVGIS estimates of solar electricity generation

Location: 48°12'29" North, 16°22'25" East, Elevation: 186 m a.s.l.,

Solar radiation database used: PVGIS-CMSAF

Nominal power of the PV system: 40000.0 kW (crystalline silicon)
Estimated losses due to temperature: 7.9% (using local ambient temperature)
Estimated loss due to angular reflectance effects: 2.8%
Other losses (cables, inverter etc.): 13.0%
Combined PV system losses: 22.1%

Fixed system: inclination=36°, orientation=0°				
Month	E_d	E_m	H_d	H_m
Jan	50200.00	1560000	1.46	45.4
Feb	88800.00	2490000	2.64	74.0
Mar	128000.00	3960000	3.93	122
Apr	172000.00	5170000	5.53	166
May	171000.00	5300000	5.64	175
Jun	168000.00	5030000	5.62	168
Jul	163000.00	5060000	5.52	171
Aug	160000.00	4960000	5.35	166
Sep	134000.00	4030000	4.36	131
Oct	94400.00	2930000	2.95	91.4
Nov	56200.00	1690000	1.69	50.7
Dec	48600.00	1510000	1.43	44.3
Yearly average	**120000**	**3640000**	**3.85**	**117**
Total for year		**43700000**		**1400**

Figure 10 - Calculation of monthly radiation result (PVGIS)

The yearly PV potential could be also cross-checked via the formula (Resch, 2022):

$$E = A * r * H * PR \quad (2)$$

Where:

E… Energy [kWh]

A…Total solar panel area [m^2]

r…Efficiency factor of module [%]

H…Annual average solar radiation on the tilted panels [kWh/m^2/year]

PR…Performance Ratio

According to a US study by the National Renewable Energy Laboratory (NREL, 2013), the land use required to install 1 MW of PV ranges from 24 000 to 36 000 m². Approximately 20-30% of the total land area is covered with PV modules. Using these assumptions, a 40 MW PV system would require an area of 0.96 km². The assumed module efficiency, sourced from the Fraunhofer Institute for Solar Energy Systems (Frauenhofer ISE, 2024), is 20%, with a performance ratio of 0.78. Applying these parameters yields an electricity generation potential of 49 GWh/year.

To meet the electrolyzer's demand, it is crucial to analyze hourly as well as yearly PV production. Since PVGIS does not provide hourly energy yields, the Global Solar Atlas web tool was used to calculate hourly PV yields for the selected year, 2023. Notably, the annual energy yields in GWh/year from both tools are consistent when compared. Table 3 illustrates the total monthly and hourly photovoltaic power output in watt-hours for a 40,000 kW/kWp system size, derived from the Global Solar Atlas data. According to this data, a 40 MW PV plant is projected to yield 47.44 GWh of energy based on the information extrapolated from the 2023 Global Solar Atlas dataset.

Table 3 - Total photovoltaic power output [Wh] for a 40000kW/kWp system size (derived from: Global Solar Atlas, 2024)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0 - 1	0	0	0	0	0	0	0	0	0	0	0	0
1 - 2	0	0	0	0	0	0	0	0	0	0	0	0
2 - 3	0	0	0	0	0	0	0	0	0	0	0	0
3 - 4	0	0	0	0	0	0	0	0	0	0	0	0
4 - 5	0	0	0	5800	147880	369040	151160	0	0	0	0	0
5 - 6	0	0	6920	418200	1455480	1812840	1445080	560800	71400	0	0	0
6 - 7	0	6840	521440	3228680	4666080	4935800	4336200	3512720	2191920	353840	6040	0
7 - 8	22480	912760	4985160	8612400	9823880	9972760	9382240	8716000	7174200	4547840	690960	17440
8 - 9	2331160	6610760	10456720	14512920	15025520	15135480	14877520	14380040	12548040	9184000	4276120	1988960
9 - 10	5943200	11175560	15031160	19152320	19310520	19455120	19156560	19155320	16928080	12878560	8369280	4724680
10 - 11	9106880	13782560	17757880	21842920	21704800	22121080	22142720	21794880	19442560	15061120	10083720	7317240
11 - 12	10599120	15451920	19468200	23185680	22388280	22888760	22828680	23067000	20573680	16696920	11265080	8489160
12 - 13	11067000	16085360	19852360	23020760	22352440	22774200	22649120	22925080	20321120	16920640	11395880	8493880
13 - 14	9525320	15317600	18627480	21123680	20476160	20558760	20573720	20916680	18098240	14876800	9839480	6714800
14 - 15	5895560	11825360	15172120	17270680	17135360	17071040	17291600	17490560	14441880	11045840	5961680	3755760
15 - 16	1982680	7745440	10737280	12683040	12939440	13230560	13493320	13083560	9933000	6401720	1477840	915360
16 - 17	21280	1991600	5661040	7326000	8094840	8669720	8936160	8116920	5044760	920560	0	0
17 - 18	0	6000	716600	2496040	3466600	4118600	4304200	3197080	631240	0	0	0
18 - 19	0	0	0	157960	892640	1527600	1432760	395200	0	0	0	0
19 - 20	0	0	0	0	0	195080	103560	0	0	0	0	0
20 - 21	0	0	0	0	0	0	0	0	0	0	0	0
21 - 22	0	0	0	0	0	0	0	0	0	0	0	0
22 - 23	0	0	0	0	0	0	0	0	0	0	0	0
23 - 24	0	0	0	0	0	0	0	0	0	0	0	0

4.1.4.2 Wind Energy Potential

The maximum usable power output of a wind turbine can be calculated by the following formula (Ziyad, 2014):

$$P = \frac{1}{2} \times \rho \times V^3 \times A \times C_p \quad (3)$$

Where:

P …the mechanical power output of a wind turbine [kW]

ρ …the air density [kg/m^3]

A … the area of the wind turbine blades [m^2]

V … wind speed [m/s]

C_p … the aerodynamic coefficient, the efficiency of a wind turbine

The maximum value of the coefficient C_p is 16/27, which equals 0.593 as first pointed by Betz (Ziyad, 2014). Indicated air density value is 1.2 kg /m3.

To obtain an initial rough estimate of the wind speed in Bruck an der Leitha, the Global Wind Atlas was utilized. As shown in Figure 11, this resource indicates an average wind speed of 6.67 m/s for the area.

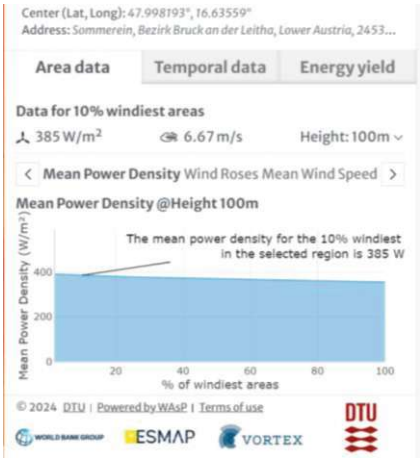


Figure 11 - Average wind speed and wind density (Source: Global Wind Atlas)

However, for a detailed analysis requiring hourly renewable profiles of wind production, data from INCA was examined. Table 4 displays extracted data from INCA, providing an hourly profile for the wind speeds recorded in the year 2023.

Table 4 - Extracted data from INCA (Geosphere Austria, 2024)

time	UU [m s-1]	VV [m s-1]	lat	lon	Wind speed [m s-1]
2023-01-01T00:00+00:00	-2,5	1,16	48.087395	16.770931	2,756011611
2023-01-01T01:00+00:00	-2,17	1,35	48.087395	16.770931	2,555660384
2023-01-01T02:00+00:00	-3,21	2,16	48.087395	16.770931	3,869069656
2023-01-01T03:00+00:00	-2,11	0,6	48.087395	16.770931	2,193649926
2023-01-01T04:00+00:00	-1,53	0,08	48.087395	16.770931	1,532090076
2023-01-01T05:00+00:00	-0,75	-0,38	48.087395	16.770931	0,840773453
2023-01-01T06:00+00:00	-0,22	-0,37	48.087395	16.770931	0,430464865
2023-01-01T07:00+00:00	-0,12	-0,42	48.087395	16.770931	0,436806593
2023-01-01T08:00+00:00	0,65	-0,19	48.087395	16.770931	0,677200118
2023-01-01T09:00+00:00	-0,4	0,39	48.087395	16.770931	0,558659109
2023-01-01T10:00+00:00	-1,22	-0,3	48.087395	16.770931	1,256343902
2023-01-01T11:00+00:00	-0,9	0,3	48.087395	16.770931	0,948683298
2023-01-01T12:00+00:00	-1,46	-0,15	48.087395	16.770931	1,467685252
2023-01-01T13:00+00:00	-2,33	2,02	48.087395	16.770931	3,083715292

As INCA data is showing surface-level wind speed (Haiden et al., 2010), the approach of wind profile power law relationship was used to convert the surface-level wind speed to estimated wind speeds at 100 meters. Wind profile power law formula represents a relationship between the wind speeds at different heights (Jung et al., 2021, p.8485):

$$\frac{u}{u_r} = \left(\frac{z}{z_r}\right)^{\alpha} \quad (4)$$

Where:

u…wind speed at surface level height of 10m (m/s)

u_r = wind speed at reference height of 100m (m/s)

z…height (m)

z_r …reference height (m)

α … wind shear exponent

At the surface level, INCA data indicated a wind speed of 2.64 m/s. Wind shear exponents can vary greatly, influenced by a wide range of factors. They range from 0.1 over smooth terrain like open water to 0.4 over rough terrain such as heavily built-up areas, and also vary with atmospheric stability (Yan et al., 2022, p.2). In the thesis,

an average wind shear exponent of 0.3 was chosen. By applying interpolation using the wind profile power law, the average wind speed at a height of 100 meters was recalculated to be 6.68 m/s. This result aligns with the wind speed estimate provided by the Global Wind Atlas.

Now that hourly wind speed data has been interpolated to a height of 100 meters, the hourly energy generation can be calculated. This calculation requires knowledge of the wind speed curve as well as frequency distribution of a wind turbine. The power curve of a wind turbine indicates the produced electricity at different wind speeds.

For the evaluation, the ENERCON E126 turbine was selected, which has a rated power of 4.2 MW. Technical data of the selected turbine are shown in the Table 5. The size of the wind farm, accommodating 10 turbines, results in the total capacity of 42 MW.

Table 5 - Technical data of the selected wind turbine (Derived from: ENERCON, 2024)

Wind Power Turbine Data Sheet					
Manufacturer	Enercon				
Type	E-126 EP4		**Generator**		
Rated Power	4 200,0	kW	Type	synchronous	
Cut-in wind speed	3,00	m/s	Number	1	
Rated wind speed	13,5	m/s	Speed, max	11,6	U/min
Cut-out wind speed	34	m/s	Voltage	690	V
Rotor			Grid connection	inverters	
Diameter	127	m	Grid frequency	50	Hz
Swept area	12 688,0	m2	Manufacturer	Enercon	
Number of blades	3		**Tower**		
Rotor Speed, max	11,6	U/min	Hub height	99	m
Tipsspeed	77	m/s	Type	steel tube/hybrid	
Material	GRP		Shape	conical	
Power density 1	331	W/m2	Corrosion protection	painted	
Power density 2	3	m2/kW	Manufacturer	Enercon	

The power output of wind turbines is influenced by several factors, including the size of the wind farm, wind speed, turbine height and rotor diameter (IRENA and ILO, 2023).

By matching the frequency distribution data with the power curve of the selected turbine, the energy yield can be calculated. The online tool from Volker Quasching incorporates the power curve data for its calculations, as shown in Figure 12.

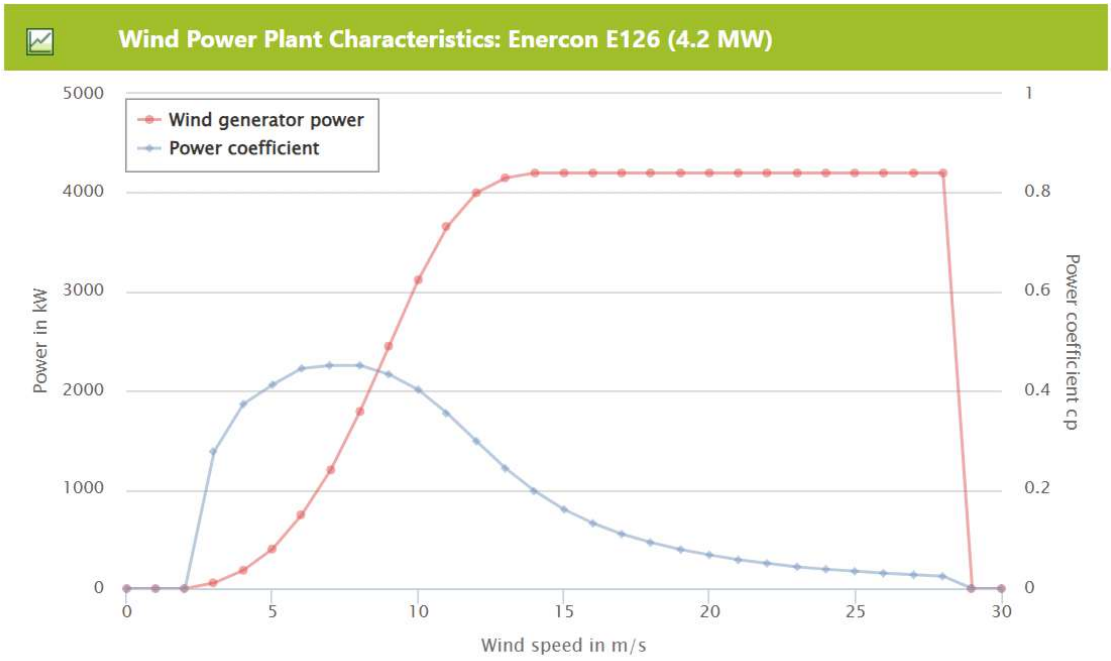


Figure 12 - Power curve for Enercon E126 turbine (source: Wind Park Performance Analysis (volker-quaschning.de))

The calculation the energy production of a wind farm can be done by combining all the data mentioned above - the power curve of the wind turbine as well as the frequency distribution of wind speed using data from INCA. Based on the hourly wind speed data from INCA, Figure 13 shows the wind frequency distribution, indicating how many hours certain wind speeds occurred over the period of one year, in this case, 2023.

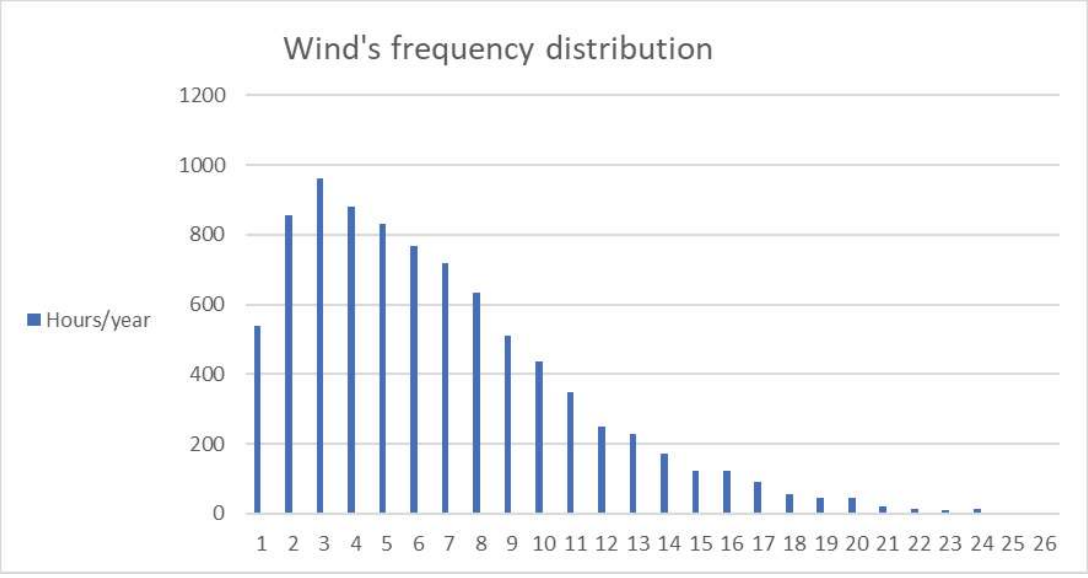


Figure 13 - Winds frequency distribution derived from INCA data

The formula energy equals power over time is applied in this context. Here, 'time' is represented by the frequency distribution of wind speeds throughout the year. For each wind speed encountered, the corresponding power output from the turbine's power curve is determined. The energy output for each wind speed is then calculated by multiplying this power output by the number of hours that specific wind speed was observed. This process is repeated for every wind speed recorded in the reference year 2023. The result of the calculation is presented in Table 6. Finally, the total annual energy generation is derived by summing up the energy outputs for all wind speeds encountered throughout the year. With this method result for the yearly energy generation is around 112 GWh per year.

Table 6 - Calculation of wind energy output depending on the wind's frequency distribution

Wind Speed [m/s]	Hours/year	kW	Energy Output [kWh]
1	539	0	0
2	854	0	0
3	962	580	519461
4	879	1850	1513946
5	832	4000	3098368
6	767	7450	5319874
7	717	12000	8010324
8	633	17900	10548882
9	510	24500	11632845
10	437	31200	12693626
11	348	36600	11857961
12	251	40000	9347240
13	227	41500	8770486
14	172	42000	6725544
15	122	42000	4770444
16	121	42000	4731342
17	90	42000	3519180
18	57	42000	2228814
19	44	42000	1720488
20	46	42000	1798692
21	22	42000	860244
22	12	42000	469224
23	10	42000	391020
24	12	42000	469224
25	4	42000	156408
26	4	42000	156408

Table 7 presents an extract of the data from INCA, with all applied formulas mentioned, including the wind profile power law and the power output formula.

Table 7 - Calculation of wind energy output hourly (extract)

time	UU [m s/1]	VV [m s/1]	lat	lon	Wind speed [m s/1]	Reference height	Target height	Wind Shear exponent	Interpolated Wind speed [m/s]	Wind Speed Rounded [m/s]	kW	Energy Output [kWh]
2023-01-01T00:00+(	-2,5	1,16	48.087395	16.770931	2,756011611	5	100	0,3	6,987427082	7	12000	11172
2023-01-01T01:00+(	-2,17	1,35	48.087395	16.770931	2,555660384	5	100	0,3	6,479468559	6	7450	6935,95
2023-01-01T02:00+(	-3,21	2,16	48.087395	16.770931	3,869069656	5	100	0,3	9,809407908	10	31200	29047,2
2023-01-01T03:00+(	-2,11	0,6	48.087395	16.770931	2,193649926	5	100	0,3	5,561648885	6	7450	6935,95
2023-01-01T04:00+(	-1,53	0,08	48.087395	16.770931	1,532090076	5	100	0,3	3,884369588	4	1850	1722,35
2023-01-01T05:00+(	-0,75	-0,38	48.087395	16.770931	0,840773453	5	100	0,3	2,131646752	2	0	0
2023-01-01T06:00+(	-0,22	-0,37	48.087395	16.770931	0,430464865	5	100	0,3	1,091374885	1	0	0
2023-01-01T07:00+(	-0,12	-0,42	48.087395	16.770931	0,436806593	5	100	0,3	1,107453324	1	0	0
2023-01-01T08:00+(	0,65	-0,19	48.087395	16.770931	0,677200118	5	100	0,3	1,716932696	2	0	0
2023-01-01T09:00+(	-0,4	0,39	48.087395	16.770931	0,558659109	5	100	0,3	1,416390908	1	0	0
2023-01-01T10:00+(	-1,22	-0,3	48.087395	16.770931	1,256343902	5	100	0,3	3,185259224	3	580	539,98
2023-01-01T11:00+(	-0,9	0,3	48.087395	16.770931	0,948683298	5	100	0,3	2,405234921	2	0	0
2023-01-01T12:00+(	-1,46	-0,15	48.087395	16.770931	1,467685252	5	100	0,3	3,721081449	4	1850	1722,35
2023-01-01T13:00+(	-2,33	2,02	48.087395	16.770931	3,083715292	5	100	0,3	7,818267403	8	17900	16664,9
2023-01-01T14:00+(	-1,33	0,97	48.087395	16.770931	1,646147017	5	100	0,3	4,173542738	4	1850	1722,35

To estimate the yearly energy production of a wind turbine or a wind farm, various online calculation tools are also available. The tool provided by Volker Quasching was employed to cross-check the generation data for the wind turbine, with the results presented in Figure 14. The yearly energy yield provided by the tool of 113GWh/year is in line with calculations based on hourly INCA data.

To supply the electrolyzer demand effectively, it is essential to analyze hourly production data. Just as the yearly PV production was calculated, it is equally crucial to conduct an hourly analysis for the wind plant. For this purpose, hourly generation data from INCA for the year 2023 was utilized. For a 40 MW wind plant, this analysis indicated an annual production of 112 GWh.

Results - Wind Park Performance Analysis	
Location:	Bruck an der Leitha
Wind power plant:	Enercon E126 (4.2 MW)
Wind generator power:	4200 kW
Rotor diameter:	127 m
Rotor area:	12667.7 m^2
Maximum performance coefficient:	0.451
Number of wind generators:	10
Total wind park power:	42 MW
Mean wind speed:	6.69 m/s
Mean wind power density:	350.3 W/m^2
Mean wind park power:	12.93 MW
Annual electricity generation:	113.303 GWh/a
Average households (3392 kWh/a):	33403
Full load hours:	2698 h/a
Investment cost:	50.4 Mio. €
O&M cost:	1.512 Mio. €/a
Levelised electricity cost:	5.87 €ct/kWh

Figure 14 - Calculation of the energy production of a wind farm (Source: Volker Quasching, 2024)

4.1.5 Final Electricity Mix

In this chapter, explored is the electricity mix for the electrolyzer is highlighted. As mentioned, the analysis includes an hourly breakdown for the year 2023, detailing the electricity demand and the contributions from wind and solar power plant.

The Table 8 presents an excerpt from a comprehensive dataset that lists the hourly electricity demand for every hour of the year. The first column of this table shows the hourly electricity demand of the electrolyzer. The subsequent columns detail the hourly electricity generation from the chosen power sources. Specifically, solar power plant, with a capacity of 40 MW, contributes a total of 47 GWh annually. Additionally,

the 40MW wind park generates 112 GWh per year. Any remaining electricity demand is met by the electricity grid.

Table 8 - Hourly Electricity Demand and Generation Summary for the Year 2023

	Electrolyzer Demand	PV-output 40 MW System size	Wind-Output 40MW System size	Electricity from the grid
	[kWh]	*[kWh]*	*[kWh]*	*[kWh]*
	328 333 333	**47 444 527**	**111 818 369**	**182 512 554**
date	**load**	**PV-output**	**Wind-output**	**El-Buy from**
01.01.2023 00:00	37 481,0	0,0	11 172,0	26 309,0
01.01.2023 01:00	37 481,0	0,0	6 936,0	30 545,0
01.01.2023 02:00	37 481,0	0,0	29 047,2	8 433,8
01.01.2023 03:00	37 481,0	0,0	6 936,0	30 545,0
01.01.2023 04:00	37 481,0	0,0	1 722,4	35 758,6
01.01.2023 05:00	37 481,0	0,0	0,0	37 481,0
01.01.2023 06:00	37 481,0	0,0	0,0	37 481,0
01.01.2023 07:00	37 481,0	22,5	0,0	37 458,5
01.01.2023 08:00	37 481,0	2 331,2	0,0	35 149,8
01.01.2023 09:00	37 481,0	5 943,2	0,0	31 537,8
01.01.2023 10:00	37 481,0	9 106,9	540,0	27 834,1
01.01.2023 11:00	37 481,0	10 599,1	0,0	26 881,9

By aggregating these contributions, the total electricity mix for the electrolyzer would comprise 53% of the electricity supplied by the grid, while 47% is sourced from renewable power plants. The electricity mix is shown in the Figure 15.

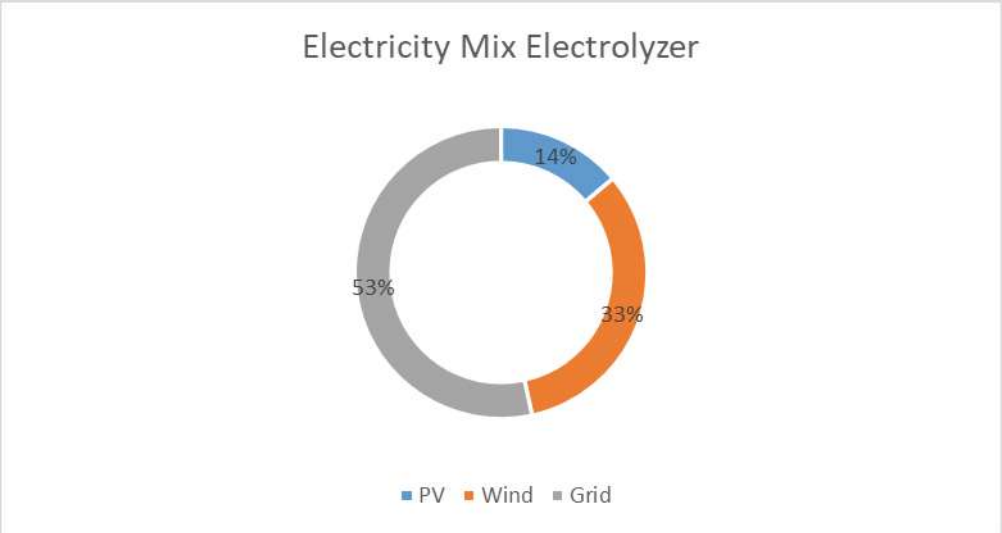


Figure 15 - Electricity Mix of the Electrolyzer

4.2 Green Hydrogen Import from Tunisia

4.2.1 Energy Imports

The predominant share of energy consumed in Austria is sourced from imports, with a notable increase from 68% in 2021 to 87% in the subsequent year, as highlighted by the Bundesministerium Klimaschutz, Umwelt, Energie, Mobilität, Innovation und Technologie (2023). Notably, only bioenergy and energy harnessed from water are produced domestically, while approximately two-thirds of Austria's energy demands rely on imports, encompassing resources such as oil, coal, and natural gas (Bundesministerium Klimaschutz, Umwelt, Energie, Mobilität, Innovation und Technologie, 2023). Given these dependencies, the necessity for energy imports to fulfil national demands remains apparent. One potential solution lies in utilizing hydrogen, the simplest molecule, as a green energy carrier (Kasper et al., 2017). Due to the increase in the energy prices and concerns over energy security and climate change, it is essential for the national strategies to emphasize diversifying the sources of supply, particularly during the initial scaling phase of the hydrogen economy (Deloitte, 2023).

One more reason to consider imports is the land constraints in Europe. Densely populated regions may struggle to find sufficient land for scaling up green hydrogen production through solar and wind farms, whereas countries like Australia and parts of Africa and Latin America, with abundant land and renewable resources, can produce cost-competitive green hydrogen (Deloitte, 2023). However, emerging markets and developing economies face barriers such as inconsistent tariffs, financial instability of power companies, and land acquisition challenges. Effective policy, regulation, and financial innovation are crucial to mitigate these risks and enhance project bankability (IEA, 2023d, p.65).

4.2.2 Energy Landscape and Risk Assessment in Tunisia

In North Africa, the cost of electricity from renewable sources is significantly lower and the full-load hours for electricity generation for a PV exceed sometimes 4000

hours per year, which leads to lower hydrogen production costs compared to Austria (Fraunhofer, 2021). Tunisia has been chosen for the analysis of green hydrogen production due to the affordable renewable electricity generation capabilities. Tunisia, with tis abundant renewable energy sources like solar and wind, offers a promising opportunity for exploring the import of green hydrogen. The country's location and renewable energy sources potential in large-scale production make it an attractive prospect, especially considering its proximity to key markets withing the European Union (GIZ, 2021).

As electricity cost play a crucial role in the production of hydrogen, it is important to look closely at electricity generation potential.

Global horizontal irradiation (GHI) and direct normal irradiation (DNI) are critical for assessing the theoretical PV potential, as they indicate the availability of solar energy without specific technical considerations (The World Bank, 2020). As illustrated in the Figures 16 and 17 provided by the World Bank (2020), Tunisia exhibits higher GHI and DNI levels than Europe, highlighting its superior suitability for PV power generation.

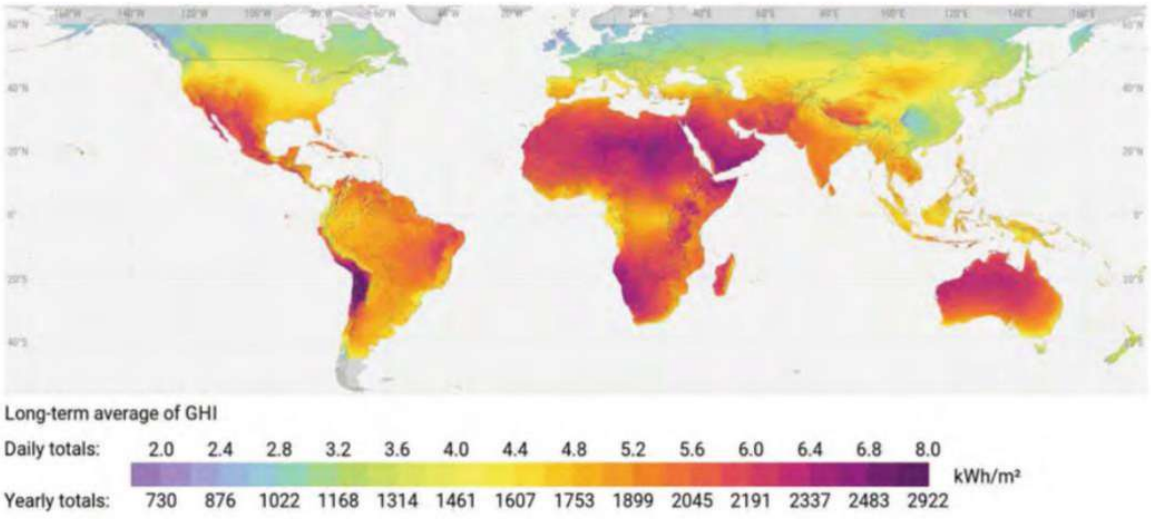


Figure 16 - Global Horizontal Irradiation: Long-term yearly average (World Bank 2020, p.25)

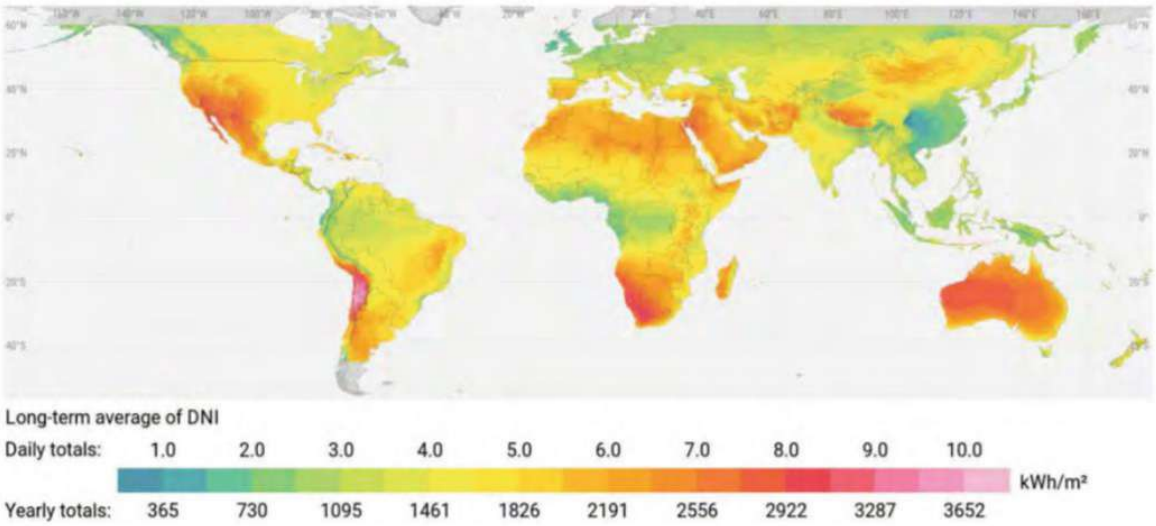


Figure 17 - Direct Normal Irradiation: Long-term yearly average (World Bank 2020, p.25)

Exceptional conditions for solar PV with photovoltaic electricity potential exceeding 4.5kWh/kWp in Tunisia could enable the technology to be deployed at a greater scale (The World Bank, 2020). Considering Tunisia, it is analyzed if the solar resource and PV potential could be used to take advantage of the solar energy and green hydrogen production.

While some other North African countries possess greater renewable energy potential, Tunisia stands out due to its favorable political and economic environment. Tunisia shows lower risk level compared to its regional counterparts. Moreover, Tunisia's infrastructure, including the pipeline linking to the EU, offers potential for hydrogen exports (GIZ, 2021). Figure 18 outlines the risk levels per country in North Africa and the Middle East.

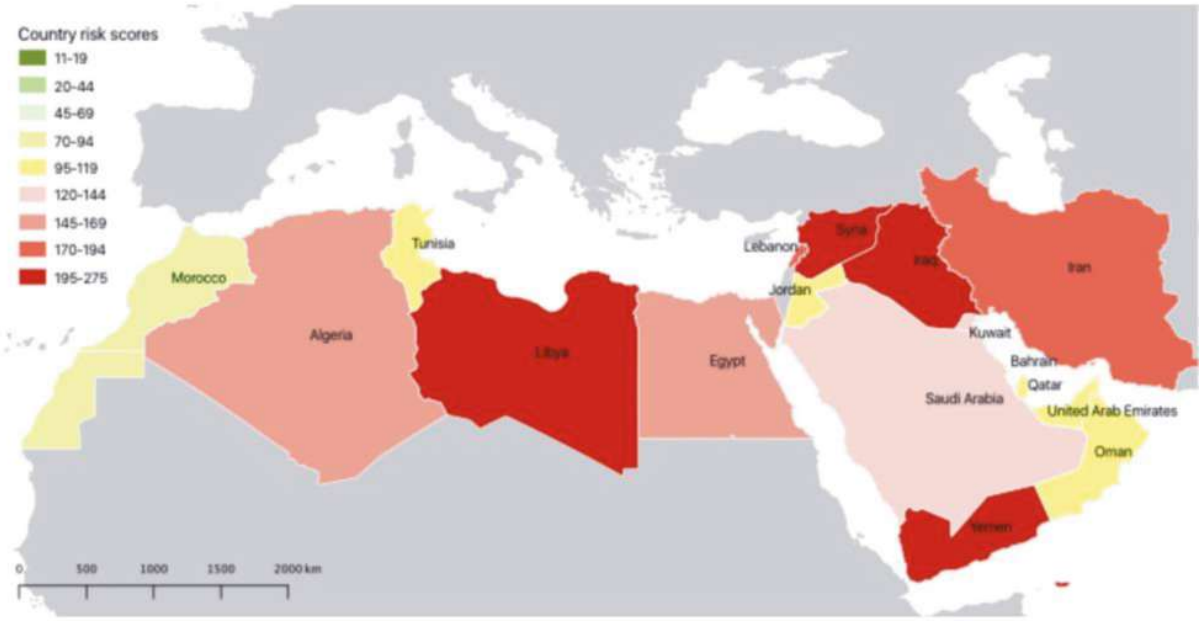


Figure 18 - Country Risk Levels (Source: GIZ, 2021, p.16)

Tunisia's wind energy potential is concentrated in regions such as the northeast, central west, and southwest, covering around 18.000 km² of the country. With considerations like grid proximity factored in, an exploitable area of 1.700 km² presents an estimated wind power capacity of about 10.000 MW. Additionally, recent studies suggest a substantial offshore wind potential of approximately 250 GW, highlighting promising opportunities for wind energy development in Tunisia (GIZ, 2021). Figure 19 shows suitable regions for wind power generation for Tunisia.

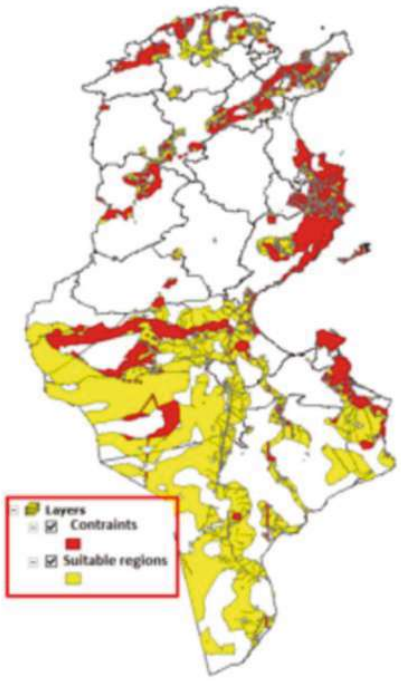


Figure 19 - Suitable regions for wind power in Tunisia (Source: GIZ, 2021, p.21)

Analysis and forecast of IEA (2023b) shows insignificant storage capacity growth for North Africa (Figure 20) which can pose a problem due to the high renewable's penetration. One solution to address this issue would be the production of green hydrogen.

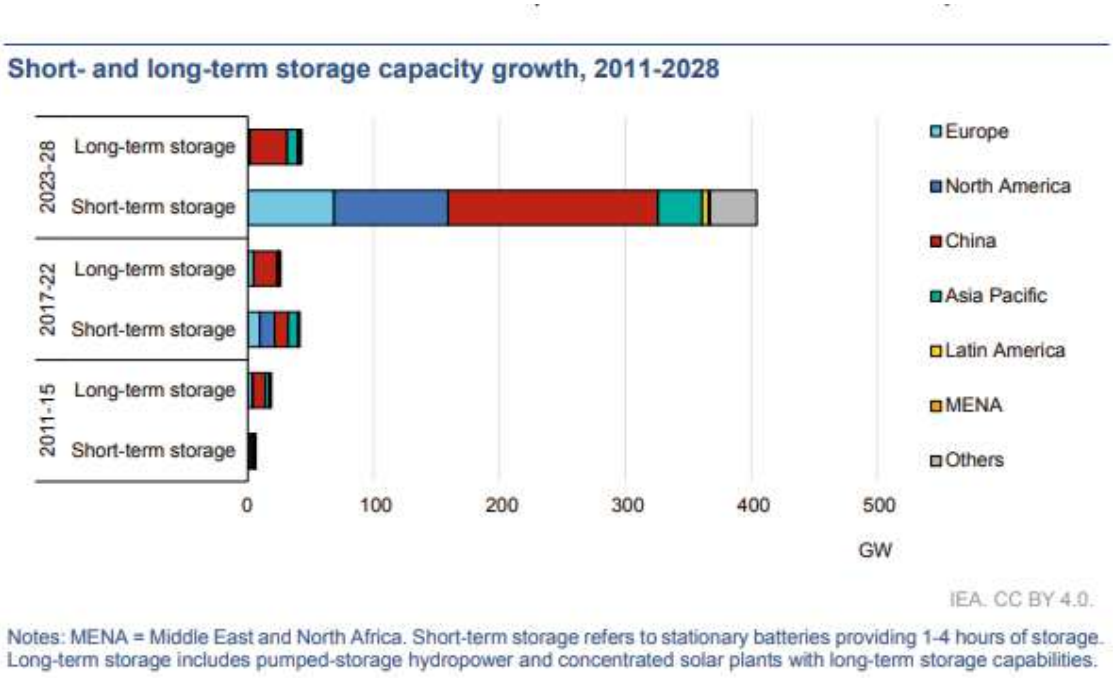


Figure 20 – Short- and long-term storage capacity growth (Source IEA, 2023b, p.80)

In summary, Tunisia holds substantial renewable electricity potential, currently utilizing only 3% of its total potential. This includes 840GW for solar PV, 110 GW for wind onshore and 250GW for wind offshore (GIZ, 2021).

Desert regions face water scarcity challenges, prompting coastal cities to consider desalination plants as a solution to ensure water availability. Alternative technologies may be employed in arid regions to address the water needs of electrolysis, including systems for harvesting water from the atmosphere (Gado et al., 2024, p.530).

4.2.2.1 Electricity Generation Tunisia

For the case of hydrogen production in Austria, where the electrolyzer is connected to refinery requiring continuous hydrogen supply and therefore, electricity supply, the strategy involves investing in dedicated power plants and leveraging grid electricity to ensure uninterrupted operations. This continuous demand fulfillment necessitates a reliable and stable power supply.

In contrast, the import strategy from a renewable-rich nation like Tunisia involves utilizing electrolyzers and only electricity derived from wind and solar power plants. Here, the emphasis is less on continuous production of the refinery, as the imported hydrogen allows for storing the produced hydrogen. The electricity strategy in this scenario focuses on flexibility in production, accommodating intermittent supply to optimize the utilization of renewable resources. The sizing of the electrolyzer is of the same capacity as the Austrian one, considering the aim to fulfill other half of the refinery demand through imports. Therefore, the required electricity remains 328 GWh/year, mirroring the demand level for locally produced hydrogen.

4.2.2.2 Solar Energy Potential Tunisia

The aim is to achieve an equal split of electricity generation between wind and solar, totaling required 328 GWh/year, for which a 100 MW capacity PV plant was determined. Using the Global Solar Atlas, yearly PV yields for a selected location and

capacity in Tunisia were calculated. Table 9 presents data for the entire year regarding the monthly and annual PV output for a 100MW plant in Tunisia.

Table 9 - Estimation of solar electricity generation for Tunisia (Global Solar Atlas, 2024)

	PVOUT_specific	PVOUT_total	DNI
	kWh/kWp	kWh	kWh/m²
Jan	129,6	12,955,581.2	140,3
Feb	131,8	13,181,213.2	140
Mar	156,7	15,671,953.5	163,8
Apr	157,1	15,709,805.2	164,6
May	163,3	16,328,289.5	188,1
Jun	159,7	15,965,851.5	202,3
Jul	168,1	16,807,392.8	212,8
Aug	164,4	16,439,389.2	190,4
Sep	144,6	14,463,821.3	143,5
Oct	138,3	13,831,829.2	137,7
Nov	125,1	12,513,335.7	132,4
Dec	122,9	12,289,991.5	135
Yearly	1761,6	176 158 453,80	1951

4.2.2.3 Wind Energy Potential Tunisia

As seen in Figure 21, the Global Wind Atlas illustrates an average wind speed of 7.95 m/s at a selected location in Tunisia.

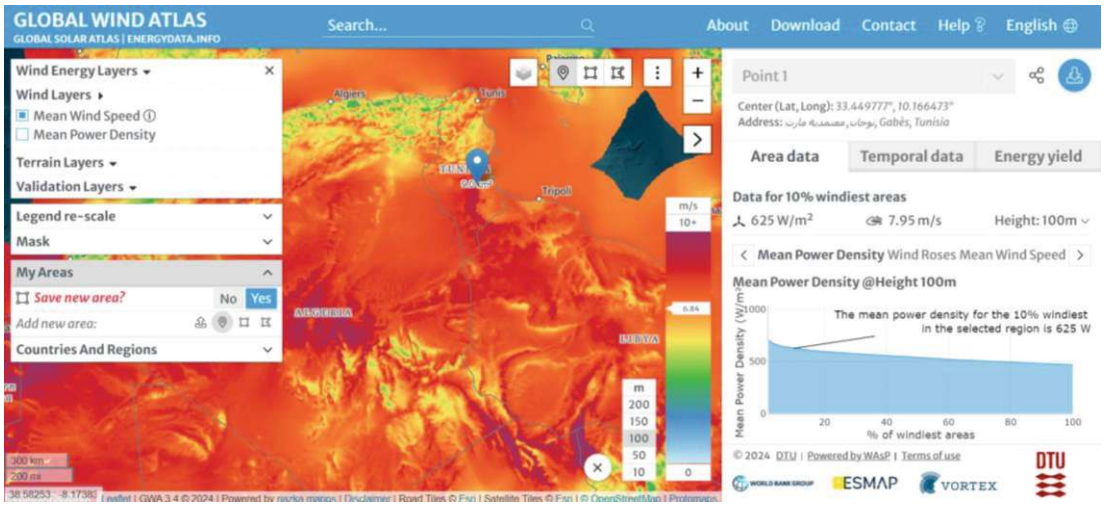
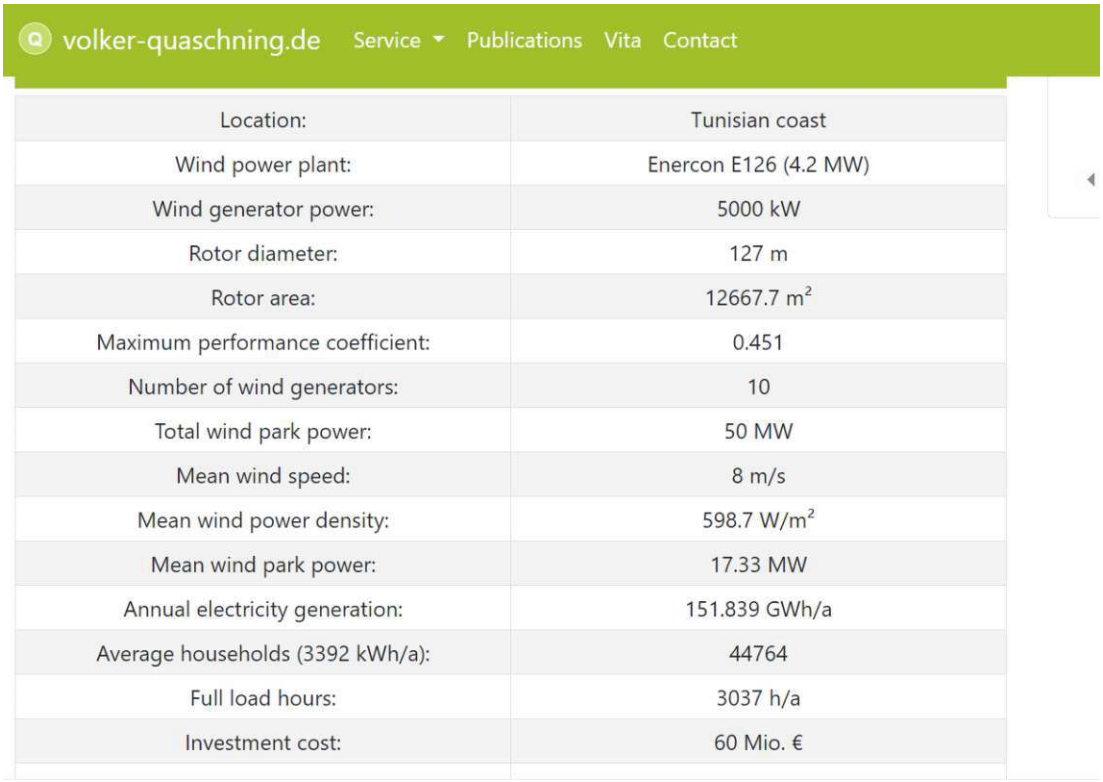


Figure 21 - Wind Energy Data for Tunisia (Source: Global Wind Atlas)

The Volker-Quaschnig tool is used to estimate the yearly yield for wind energy based on wind park capacity. Utilizing the Enercon E-126 turbine, similar to the one used in

the Austrian plant, the electricity generation for the site is anticipated to reach 152 GWh/year as shown in Figure 22.



Location:	Tunisian coast
Wind power plant:	Enercon E126 (4.2 MW)
Wind generator power:	5000 kW
Rotor diameter:	127 m
Rotor area:	12667.7 m^2
Maximum performance coefficient:	0.451
Number of wind generators:	10
Total wind park power:	50 MW
Mean wind speed:	8 m/s
Mean wind power density:	598.7 W/m^2
Mean wind park power:	17.33 MW
Annual electricity generation:	151.839 GWh/a
Average households (3392 kWh/a):	44764
Full load hours:	3037 h/a
Investment cost:	60 Mio. €

Figure 22 - Wind Energy Generation Data (Source: Volker-Quasching.de)

5 Economic Assessment and Scenarios – the Costs of Hydrogen

5.1 Methodology – Levelized Cost of Hydrogen

The aim is to calculate levelized cost of hydrogen in EUR/kg of hydrogen including the costs of the whole chain as accurately as possible starting from investing in renewable electricity plants and costs related to them, then electrolyzer costs, transport costs. The scope of the calculation is shown in Figure 23.

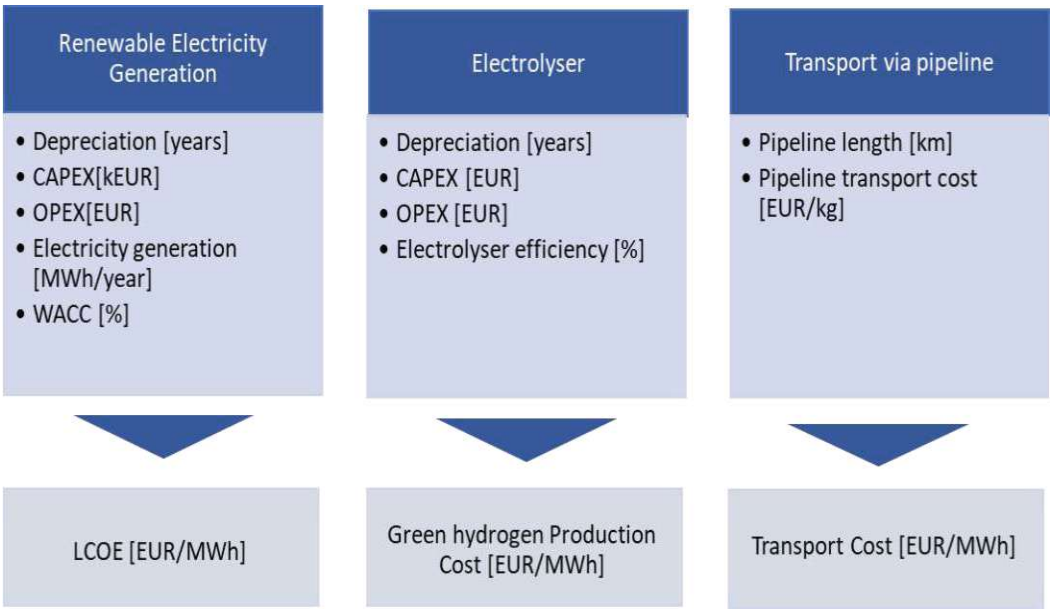


Figure 23 - Main costs included in the LCOH calculation

To calculate the Levelized Cost of Hydrogen (LCOH), all relevant cost components need to be combined. The formula provided by Agora Industry and Umlaut (2023) is used for this calculation.

$$LCOH = \frac{LHV}{\eta} \times \left(\left(\frac{\frac{i}{100} \times (1+\frac{i}{100})^n}{(1+\frac{i}{100})^n - 1} + \frac{OPEX}{100} \right) \times \frac{CAPEX}{\tau} + E \right) \quad (5)$$

Where

LCOH … Levelized cost of hydrogen (EUR/kgH_2)

LHV … Lower Heating Value (kWh/kgH_2)

i … discount rate (%)

n … lifetime (a)

E … electricity costs (EUR/kWh)

Ƞ … system efficiency related to the LHV

τ … full load hours (h)

OPEX … operational expenditures (% CAPEX)

CAPEX … capital expenditures (EUR/kW)

It is recommended to use the lower heating value (LHV) in efficiency calculation to maintain consistency and avoid errors that can occur if the higher heating value (HHV) and LHV are not consistently applied. Most of the efficiency data in the reviewed literature are based on the LHV (Agora Industry and Umlaut, 2023).

This system is composed primarily of the electrolysis subsystem, specifically the PEM electrolyzer. In Austria, the operation of the hydrogen system relies on locally generated renewable energy sources (wind power and photovoltaic) and uses grid electricity to cover any deficits. For the scenario in Tunisia, the hydrogen cost calculation is exclusively based on renewable electricity. Each hydrogen system size is determined as 39 MW, in alignment with the refinery demand. Excess renewable electricity is it not considered to have an alternative application (such as reselling or feeding into the electricity grid). It is further assumed that the generated hydrogen is immediately discharged and used on-site, removing the necessity for a storage system.

The local renewable energy production is directly used as the power source for the hydrogen system. With the system's CAPEX and OPEX accounted for, the hydrogen production costs for each scenario within the parameter study can be calculated and analyzed, as detailed in the chapters.

In the import scenario, assumed is that hydrogen pipelines will be constructed using the same components as natural gas pipelines. It is also assumed that hydrogen storage will become as widely available as natural gas storage (European Hydrogen Backbone, 2021a).

5.2 Levelized Cost of Electricity

Initially, the LCOH values are determined by assessing the renewable energy potential of chosen locations, which are reflected in the Levelized Cost of Electricity (LCOE) calculation. The hydrogen system is ultimately modeled and integrated with the respective electricity generation profiles as per various scenarios. The LCOE calculations are based on assumptions which include the Weighted Average Cost of Capital (WACC), the economic lifespan of the project, Operations and Maintenance (O&M) costs and total installed costs (IRENA, 2022b).

The declining costs of solar PV and wind energy are making the production of green hydrogen more economically appealing (IRENA 2022c).

The calculate the cost of electricity, total costs should be divided with the electricity generation. The annuity of costs represents yearly average total costs of electricity generation. It can be calculated as the product of the NPV of costs and the capital recovery factor (Weißensteiner, 2022).

$$a_c = NPV_c * CRF \tag{6}$$

Where:

a_c … annuity of costs (EUR)

NPVc … NPV of costs (EUR)

CRF … Capital Recovery Factor

Capital Recovery Factor is calculated by the following formula:

$$CRF = \frac{r*(1+r)^t}{(1+r)^t-1} \tag{7}$$

Where:

r … discount rate

t … year count

NPV of costs is calculated by the following formula:

$$NPV_c = \sum_{t=1}^{T} \frac{Cot}{(1+r)^t} + C_0 \tag{8}$$

C_{ot} … Cash Outflows in year t (EUR)

C_0 … Initial investment (CAPEX) (EUR)

Finally, the LCOE is calculated by dividing the annuity of cost with the total energy production per year:

$$LCOE = \frac{a_c}{E} \tag{9}$$

Where:

a_c … annuity of costs (EUR)

E … total yearly electricity production (MWh)

Povacz et al. (2023) used the following formula:

$$LCOE = \frac{I_o + \sum_{t=1}^{n} \frac{A_t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{M_t}{(1+i)^t}} \tag{10}$$

Where:

I_0 ... CAPEX (EUR/MW)

t ... time interval

A_t ... OPEX (EUR/MW/year)

M ... total yearly electricity production (MWh)

i ... discount factor

5.3 Financial Analysis

In this chapter all relevant data regarding costs and the assumptions underlying the calculations are documented in detail. It is essential to note that all costs presented are referenced to the year 2030. It is assumed that by this time, the required technical components across supply chains will be readily available on a large industrial scale, aligning with expectations for the infrastructure development outlined.

5.3.1 Weighted Average Cost of Capital

Obtaining precise and current WACC assumptions presents challenges, as the cost of debt, the expected return on equity, and the debt-to-equity ratio differ across individual projects and countries due to a variety of influencing factors (IRENA, 2022b, p.195).

As stated in Deloitte's report (2023, p.65), the cost of capital for clean hydrogen projects should be tailored to reflect their risk profile, including considerations of local regulatory and political risks.

According to GIZ (2021), industries characterized by high risks and significant capital requirements typically attract less private financing. To draw in risk-averse investors, it is crucial to implement de-risking strategies. By using a mix of public policy and financial tools, the risks associated with green hydrogen generation in Tunisia can be controlled. These tools help in reducing investment, economics, and business risks. Combination of measures such as offering government guarantees, establishing transparent practices, streamlining processes for permits, risk mitigation clauses could significantly decrease the cost of capital, making green hydrogen projects more financially feasible. Additionally, specific financing mechanisms tailored to individual projects or sectors can further drive down costs (GIZ, 2021). The Figure 24 below is derived from Deloitte's report (2023, p.65) and divides countries into seven groups based on the Organization for Economic Co-Operation and Development (OECD) country risk classification. Current WACC levels are taken from International Renewable Energy Agency calculations, while future values are extrapolated based on literature expectations. This methodology provides a country-specific, risk-adjusted WACC for calculating the LCOH. The decreasing WACC trajectories reflect the expected reduction in project risks as hydrogen technologies are increasingly adopted and demand rises (Deloitte, 2023).

The Figure 24 illustrates these WACC levels and their projected trends:

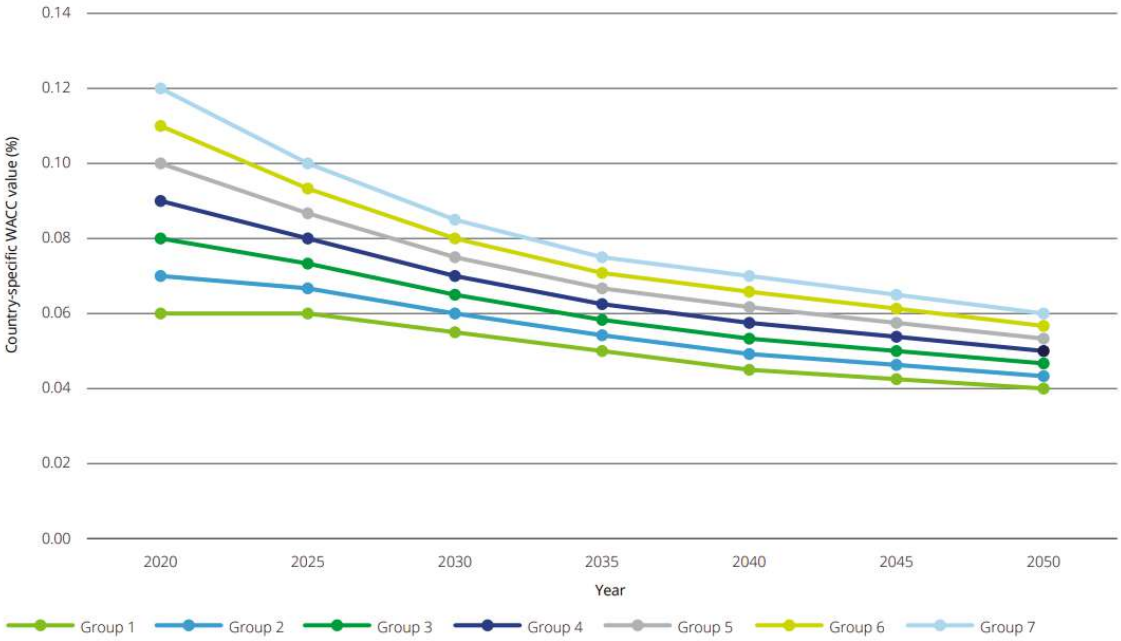


Figure 24 - Country Specific WACC development over the years (Deloitte, 2023, p.65)

Note: Groups of countries and regions are defined by the following classification. Group 1: Europe, North America, Australia, Chile. Group 2: China, Saudi Arabia, United Arab Emirates. Group 3: India, Qatar, Mexico, Morocco. Group 4: Colombia, South Africa. Group 5: Brazil, Egypt, Turkey. Group 6: Namibia, Nigeria, Ukraine. Group 7: Argentina, Iran, Tunisia.

IRENA (2022b, p.194) provided WACC figures for renewable projects for both OECD and non-OECD countries, which are detailed in the Table 10.

Table 10 - Standardized Assumption for LCOE Calculation (IRENA, 2022b, p.194)

Technology	Economic life (years)	Weighted average cost of capital (real)	
		OECD and China	Rest of the world
Wind power	25	7.5% in 2010 falling to 5% in 2020	10% in 2010 falling to 7.5% in 2020
Solar PV	25		
CSP	25		
Hydropower	30		
Biomass for power	20		
Geothermal	25		

The modelling from GIZ (2021) suggests that for Tunisia, the WACC in 2030 is projected to be 13.68%. Table 11 summarizes data from various literature sources on the WACC for renewable projects. To be on the conservative side, for Tunisia, WACC from GIZ (2021) is considered in the calculation. It should be noted that extracting meaningful insights from this data can be challenging due to inconsistencies in methodologies across studies, as well as variations in the years, countries, and technologies referenced (IRENA, 2022b, p.195). The WACC for Austria is taken as the average derived from the literature.

Table 11 - WACC data used in the calculation

	Unit	Value	Source
WACC wind AT	%	5,9%	Bjarne, 2020
WACC ren projects (non OECD avg - Tunisia)	%	10,4%	Bjarne, 2020
WACC ren projects (non OECD avg - Tunisia)	%	10,0%	IRENA, 2022b
WACC AT (used for LCOH calculation), year 2030	%	5,7%	Deloitte, 2023
WACC AT (used for LCOH calculation), year 2050	%	4,0%	Deloitte, 2023
WACC AT (used for LCOH calculation)	%	7,5%	IRENA, 2022b
WACC Tunisia (used for LCOH calculation), year 2030	%	8,3%	Deloitte, 2023
WACC Tunisia (used for LCOH calculation), year 2050	%	6,0%	Deloitte, 2023
WACC Tunisia	%	13,7%	GIZ, 2021
Used in the calculation - Austria	**%**	**5,8%**	
Used in the calculation - Tunisia	**%**	**13,7%**	

5.3.2 Electricity Cost for the Electrolyzer

As previously mentioned, the LCOH cost analysis begins with the analysis of the electricity costs that feed into the electrolyzer, considering the investments in power plants. Table 12 presents the data for the investment costs associated with the PV power plants. Solar CAPEX is going down due to the oversupply of the modules (IEA, 2022, p.109). Also, improvements in module efficiency significantly lowered the costs by reducing the required surface area and materials per watt, as well as decreasing overall system area and balance of plant costs (IRENA. 2022b, p.57).

Table 12 - CAPEX data for Solar PV

	Unit	Cost	Source
Renewable Power			
Solar			
Solar PV Capex (2021)	EUR/kW	530-800	Frauenhofer, 2021
Solar PV Capex (2030)	EUR/kW	550	NREL, 2021
Solar PV Capex	EUR/kW	805	Povacz et al, 2023
Used in the Calculation	**EUR/kW**	**550**	

Table 13 provides the detailed CAPEX data for wind power projects. Regarding the CAPEX for wind turbines, there are steel supply chain constraints and disruptions which results in higher turbine prices (Wind Europe, Rystad Energy, 2023).

Table 13 - CAPEX data for wind power plant

	Unit	Cost	Source
Renewable Power			
Wind			
Wind Capex	EUR mn / MW	1,2	Mooradpoor et al, 2023
Wind Capex	EUR mn / MW	1,4-2	Frauenhofer, 2021
Wind Capex	EUR mn / MW	1,4	Povacz et al, 2023
Used in the Calculation	**EUR mn / MW**	**1,2**	

Table 14 presents the O&M costs. For a solar plant in Austria, an O&M cost of 13.3 EUR/MW is utilized (from Povacz et al., 2023). For Tunisia, the data are sourced from IRENA (2022b), which indicates that non-OECD countries generally have lower O&M costs due to cheaper labor and materials.

Table 14 - Operations and Maintenance costs for solar PV

	Unit	Cost	Source
Renewable Power			
Solar			
O&M of a solar plant	% of CAPEX	5	Nicita et al, 2020
Total O&M solar OECD country	EUR/kW/y	16,6	IRENA, 2022b
Total (Fixed O&M) solar plant	EUR/MW/y	13,3	Povacz et al, 2023
Total O&M solar non-OECD country	EUR/kW/y	8,6	IRENA, 2022b

For wind O&M costs, the most up-to-date data from Mooradpool et al. (2023) has been used. The wind O&M data are summarized in the Table 15.

Table 15 - Operations and Maintenance costs for wind power plant

	Unit	Cost	Source
Renewable Power			
Wind			
Fixed O&M wind	EUR/MW/y	14 000	Mooradpoor et al, 2023
Variable O&M wind	EUR/Mwh	1,50	Mooradpoor et al, 2023
Total O&M wind OECD country	EUR/kW/y	33,63	IRENA, 2022b
Total O&M wind OECD country	EUR/kW/y	28,96	IRENA, 2022b

Applying LCOE formula and taking the costs for the electricity grid price from IEA (2019b) of 106.5 EUR/MWh for 2030 for EU, the resulted energy mix price that feed is a feed for the electrolyzer and also the share of the electricity mix are shown in the Table 16 and Table 17.

Note that these figures (except the grid electricity price) are based on electricity generation costs and not on electricity market prices.

Table 16 - Resulting electricity mix price (Austria case)

Location: Austria	Share	Price [eur/MWh]
Solar	14%	€ 135,55
Wind	33%	€ 82,18
Grid	53%	€ 106,50
Electricity mix price	€ 102,58	eur/MWh

Table 17 - Resulting electricity price (Tunisia case)

Location: Tunisia	Share	Price [eur/MWh]
Solar	50%	€ 67,45
Wind	50%	€ 86,14
Grid	0%	€ -
Energy mix price	€ 76,79	eur/MWh

As evident from results, the case for Tunisia benefits from lower electricity prices. Specifically, in the case of solar PV, Tunisia enjoys a significantly higher full load hours (FLH). Of 1762 hours/year compared to Austria's 1186 hours/year. Additionally, the operations and maintenance costs for solar in Austria are higher than those in Tunisia.

5.3.3 Electrolyzer Capital Expenditure

Determining the capital expenditure of electrolyzers presents a significant challenge due to the variability in what these costs encompass. The CAPEX can fluctuate based on whether it includes just the stack or the entire system, including the balance of plant components. Additionally, many electrolyzer projects are in their early stages, and the associated costs are often confidential and not fully transparent. The International

Renewable Energy Agency (2022a) has distinguished between the costs of whole systems and stack-only configurations. For the purposes of this thesis, the analysis focuses exclusively on the costs of whole systems. Notably, IRENA projects that, by 2050, the costs associated with electrolyzers could decrease by a factor of five (IRENA, 2020a). Advances in efficiency and lifespan, along with reductions in CAPEX, are anticipated due to innovation, standardization, and scaling effects. As a result, already by 2025, the energy consumption is expected to be 53 kWh/kg of hydrogen, with CAPEX projected to reach 600 EUR/kW for AE systems and 900 EUR/kW for PEM system (Kearney, 2021). Glenk et al. propose that cost reductions of approximately 4.77% per year could be achievable for PEM systems. Meanwhile, for AE systems, a yearly cost decrease of about 2.96% is considered possible (Glenk Gunther, 2019). The largest cost component of electrolyzers is the balance of plant, rather than the stack itself. Increasing the module size tends to bring significant economies of scale for the balance of plant, but less so for the stack, which cannot be dramatically increased in size due to issues like leakage, manufacturing limitations, and mechanical instability. For example, a larger compressor costs relatively less than a proportionately larger stack, which becomes much more expensive as capacity increases. Studies suggest cost reductions through economies of scale, particularly in the balance of plant components, with a cost exponent of approximately 0.60 to 0.75, indicating a less than proportional cost increase when scaling up capacity. Meanwhile, the stack's contribution to total cost grows with increased module size, highlighting the importance of optimizing balance of plant for cost efficiency (IRENA, 2020). It is important to note that the capital costs can vary between Austria and Tunisia. Constructing electrolyzer in a more residential area, such as these found in Lower Austria, necessitates stricter health and safety standards compared to less populated areas, potentially increasing overall costs in Austria.

The electrolyzer lifetime varies somewhat in reports, but it's generally agreed that AE and PEM systems have a lifetime of around 60.000 – 90.000 hours. (IEA, 2019a).

In Table 18, a synthesis of CAPEX data from diverse literature sources is provided to facilitate a more informed selection of values for calculations regarding the electrolyzer. The process involved a degree of complexity, as not all sources clearly specified the components encompassed within the CAPEX. Notably, Povacz et al.

(2023, p.11) outlined the composition of their CAPEX data, which includes electrolysis stacks, power electronics, BoP, Cathode and hydrogen Purification, BoP Anode, water Purification, System Cooling, Compression, Piping, and Instrumentation.

Table 18 - CAPEX costs for Alkalyne, PEM and SOEC electrolyzers

	Unit	Value	Source	What is included in the costs
Electrolyser				
CAPEX electrolyser PEM	EUR/kW	978	Povacz et al, 2023	including: electrolysis stacks, power electronics, BoP Cathode + H2 Purification, BoP Anode, H2O Purification,
CAPEX electrolyser PEM	EUR mn / MW	0,98	Povacz et al, 2023	System Cooling, Compression, Piping, Instrumentation, Housing, Engineering
CAPEX electrolyser PEM, year 2019	EUR mn / MW	1,1-1,8	IEA, 2019a (Future of hydrogen)	
CAPEX electrolyser PEM, year 2030	EUR mn / MW	0,60-1,4	IEA, 2019a (Future of hydrogen)	CAPEX represents system costs, including power electronics, gas conditioning and balance of plant
CAPEX electrolyser PEM, long term	EUR mn / MW	0,2-0,9	IEA, 2019a (Future of hydrogen)	CAPEX represents system costs, including power electronics, gas conditioning and balance of plant
CAPEX electrolyser PEM	EUR mn / MW	1,04	Da Silva et al (2022)	
CAPEX electrolyser	EUR mn / MW	1,45	Mooradpoor et al, 2023 (Finnish Case)	Total capital investment
CAPEX electrolyser PEM, year 2025	EUR mn/ MW	0,90	Kearney, 2021	
CAPEX electrolyser AE	EUR mn/ MW	1,00	Mooradpoor et al, 2023 (Finnish Case)	Total capital investment
CAPEX electrolyser AE, year 2025	EUR mn/ MW	0,60	Kearney, 2021	
CAPEX electrolyser AE	EUR mn/ MW	1,50	Nicita et al, 2020	Water treatment included, electrics, gas, equipment, safety system and control system
CAPEX electrolyser AE, year 2019	EUR mn/ MW	0,5-1,3	IEA, 2019a (Future of hydrogen)	CAPEX represents system costs, including power electronics, gas conditioning and balance of plant
CAPEX electrolyser AE, year 2030	EUR mn/ MW	0,3-0,8	IEA, 2019a (Future of hydrogen)	CAPEX represents system costs, including power electronics, gas conditioning and balance of plant
CAPEX electrolyser AE, long term	EUR mn/ MW	0,2-0,7	IEA, 2019a (Future of hydrogen)	CAPEX represents system costs, including power electronics, gas conditioning and balance of plant
CAPEX electrolyser SOEC, year 2019	EUR mn/ MW	2,6-5,2	IEA, 2019a (Future of hydrogen)	CAPEX represents system costs, including power electronics, gas conditioning and balance of plant
CAPEX electrolyser SOEC, year 2030	EUR mn/ MW	0,7-2,6	IEA, 2019a (Future of hydrogen)	CAPEX represents system costs, including power electronics, gas conditioning and balance of plant
CAPEX electrolyser SOEC, long term	EUR mn/ MW	0,5-0,9	IEA, 2019a (Future of hydrogen)	CAPEX represents system costs, including power electronics, gas conditioning and balance of plant
CAPEX electrolyser SOEC	EUR mn/ MW	3,75	Mooradpoor et al, 2023 (Finnish Case)	Total capital investment
Used in the calculation	**EUR mn / MW**	**1,09**		

For this thesis and analysis a PEM electrolyzer is selected due to its ability to handle variations that comes with renewable power sources (Buttler A., 2018)

5.3.4 Electrolyzer Operating Expenses

OPEX for electrolyzers are typically calculated as percentage of the initial CAPEX. Although the specific components of O&M costs are not always clearly defined, they typically encompass expenses related to wages and materials necessary for the operation and maintenance of the facility, as well as land lease payments. Table 19 displays OPEX costs, with a 3% of CAPEX figure selected based on Frauenhof's 2021 report for the calculations. In addition to these costs, utilities such as demineralized water, steam, and nitrogen costs (as outlined by Nicita et al., 2020) are to be considered and are detailed in Table 20. Previous mention has been made of electricity prices which are one the most important component of the green hydrogen costs.

Table 19 - O&M Costs for PEM electrolyzer

	Unit	Value	Source
Electrolyser OPEX			
Variable O&M costs PEM electrolyser, year 2030-2050	EUR/kWh	0,6	Deloitte, 2023
Fixed O&M costs PEM electrolyser	% of capex	2%	Mooradpoor et al, 2023
Fixed O&M costs, year 2030	EUR/kW	15,9	Deloitte, 2023
O&M costs	% of capex	3%	Frauenhofer, 2021

Table 20 - Cost of utilities for PEM electrolyzer

	Unit	Value	Source
Electrolyser Utilities			
Deionised water specific demand	kg/kg H2	10,0	Nicita et al, 2020
Deionised water cost	EUR/kg	0,01	Nicita et al, 2020
Steam specific demand (Process Steam used during run-up to h	kg/kg H2	0,1	Nicita et al, 2020
Steam cost	EUR/kg	0,01	Nicita et al, 2020
Nitrogen specific demand (Used for cleaning purpose)	g/kg H2	0,3	Nicita et al, 2020
Nitrogen cost	EUR/kg	0,3	Nicita et al, 2020

5.3.5 Land Cost

The land requirement for a 1 GW plant is approximately 0.17 square kilometers (IRENA, 2020a, p. 26). It is important to note that land costs were not included in the analysis, as these costs are highly site-specific and can vary significantly (Manna et al, 2021, p.38217).

5.3.6 Transport Costs

Extensive discussion on transport costs from various literature sources has been covered in Chapter 3.2. In the case of the import option, pipeline transportation is taken into account, with costs sourced from EHB (2021b) at a rate of 0.21 EUR per kilogram per 1000 kilometers. As explained in the Chapter 3, the way to import hydrogen from North Africa would be through the SoutH2 Corridor pipeline, which has a length of 3 000 km and this is length considered in the calculation.

5.3.7 Summary of the Economic Inputs

Table 21 and 22 presents the economic input parameters used in the calculation model.

Table 21 - Economic input parameter for investing in a solar PV and wind power plants (Austria and Tunisia)

Cost Parameter	unit	Austria	Tunisia
General			
Depreciation	years	20	20
Inflation (EUR)	%	2%	2%
WACC	%	6%	14%
Solar			
Power	MW	40	100
Investment cost/MW	kEUR/MW	550	550
Total Investment Cost	**kEUR**	**22 000**	**55 000**
Total Energy Production	MWh/y	47 445	176 158
Operations and Maintenance Cost	% of investment cost	5%	5%
Operations and Maintenance Cost	kEUR/MW/y	13,30	16,63
Total O&M costs	kEUR	**532**	**1 663**
System degradation rate	%	0,50%	0,50%
Wind			
Power	MW	42	50
Investment cost/MW	kEUR/MW	1 200	1 200
Total Invesment cost	**kEUR**	**50 400**	**60 000**
Total Energy Production	MWh/y	111 818	151 839
Land required	km2	8,00	8,00
Land Cost	EUR/ha/y	3 000	3 000
Total Land Cost	**kEUR/y**	**0**	**0**
Fixed O&M wind	EUR/MW/y	14 000	14 000
Fixed O&M Costs	EUR/MWh	1,50	1,50
Variable O&M Costs	kEUR	71	264
Total O&M costs	**kEUR**	**659**	**964**

Table 22 - Economic input parameter for a PEM electrolyzer (Austria and Tunisia)

Electrolyzer Capex			
Plant lifetime	years	20	20
Hydrogen Output	kg/h	686	686
Hydrogen Output	kg/y	5 833 333	5 833 333
Hydrogen Energy Content	kWh/kg	39,40	39,40
Electrolyzer Efficiency	%	70%	70%
Electricity Required	kWh/kg H2	56,29	56,29
Electricity Required	kWh/y	328 333 333	328 333 333
Electrolyzer Full Load Hours	h/y	8 500	8 500
Electrolyzer Capacity	MW	38,63	38,63
Electrolyzer CAPEX PEM	kEUR/MW	1 091	1091
Total Electrolyzer CAPEX	**kEUR**	**42 132,89**	**42 132,89**
Electrolyzer OPEX			
Required electricity input from the grid	MWh/y	182 512,55	-
Electricity price (EU mix, 2030)	eur/MWh	106,50	
Total electricity cost	**kEUR**	**19 437,59**	**-**
Deionised water specific demand	kg/kg H2	10	10
Deionised water cost	EUR/kg	0,01	0,01
Steam specific demand (Process Steam used during run-up to heat up the syste	kg/kg H2	0,11	0,11
Steam cost	EUR/kg	0,01	0,01
Nitrogen specific demand (Used for cleaning purpose)	g/kg H2	0,29	0,29
Nitrogen cost	EUR/kg	0,28	0,28
Total Utilities Cost	**kEUR**	**590,22**	**590,22**
O&M	% of investment cost	3%	3%
Pipeline Length	km	0	3000
Pipeline transportation cost	eur/kg	0,00	0,63
Total pipeline transportation cost	**kEUR**	**-**	**3675,00**

5.3.8 Results of economic analysis

In this section the findings from the economic analysis of a 39 MW PEM electrolyzer are presented, utilizing mentioned economic inputs. The analysis focuses on two regions: Austria and Tunisia. In the first step calculated LCOH results indicate that Tunisia has a production cost that is 0.84 EUR per kilogram lower than that of Austria. It is important to note that for the Tunisian case next to the production costs also import costs via pipeline need to be included. Additionally, the results explore sensitivities based on varying parameters such as electricity prices, WACC and CAPEX. This analysis demonstrates how these different factors influence the overall cost of hydrogen production.

As previously mentioned, Tunisia benefits from cheaper electricity prices which are main contributor to the LCOH. Good renewable energy generation potential compensates the high WACC of Tunisia. With favorable financing and suitable infrastructure, the LCOH delivered from Tunisia are therefore quite competitive.

The electricity price used in the model includes the CAPEX for both solar and wind plants. Additionally, different combinations are analyzed, considering scenarios where Tunisia invests solely in solar or solely in wind energy to determine which option is more favorable. For the Austrian case, it is also evaluated whether electricity is sourced through a PPA contract. For this analysis, a price of 70 EUR/MWh was assumed for Europe (Pexapark, 2024).

Table 23 shows the results of the two main cases for Austria and Tunisia main cases:

Table 23 - LCOH results for two main cases

Case	Production cost [EUR/kg]	Transport cost [EUR/kg]	Total LCOH [EUR/kg]
Local production in Austria	7,40	-	7,40
Import from Tunisia	6,56	0,63	7,19

Scenario in Austria is reliant on the electricity market and can be notably affected by the fluctuations in electricity prices. Completely investment-driven scenarios may demonstrate less sensitivity in certain instances. There can be a scenario structured on PPA to offer stability against fluctuations in critical factors. For the PPA price for Europe a price of 70 EUR/MWh was assumed (Pexapark, 2024). Hence, the Table 24 shows sensitivity cases for the electricity price sensitivity for the demand of the electrolyzer plant in Austria, which can be covered either through the grid or PPA, excluding the portion of demand already addressed by the invested PV and wind power plants.

Table 24 – Sensitivity: LCOH produced in Austria (EUR per kg of hydrogen) with varying electricity price

Electricity price [EUR/MWh]	LCOH Austria [EUR/kg]
27	5,38
37	5,62
47	5,88
57	6,13
67	6,38
77	6,64
87	6,89
97	7,15
107	7,40
117	7,65
127	7,91
137	8,16
147	8,42
157	8,67
177	9,18

Note: Green signifies a lower cost than the reference vale for production and import from Tunisia (reference value 7.19 EUR/kg). Red signifies a higher cost than the reference value for Tunisia.

Due to the lack of transparency and substantial variability in CAPEX data, along with the potential efforts directed towards reducing CAPEX costs, Table 25 shows further sensitivities calculated. The analysis includes an examination of how the calculated LCOH are impacted by changes in both CAPEX values and electricity prices.

Table 25 – Sensitivity: LCOH produced in Austria (EUR per kg of hydrogen) with varying CAPEX and electricity price

	CAPEX [kEUR/MW]														
	€ 891,00	€ 1 091,00	€ 1 291,00	€ 1 491,00	€ 1 691,00	€ 1 891,00	€ 2 091,00	€ 2 291,00	€ 2 491,00	€ 2 691,00	€ 2 891,00	€ 3 091,00	€ 3 291,00	€ 3 491,00	€ 3 691,00
Electricity Price [EUR/MWh]															
€ 26,50	€ 4,61	€ 5,37	€ 6,26	€ 7,29	€ 8,46	€ 9,76	€ 11,19	€ 12,76	€ 14,46	€ 16,29	€ 18,27	€ 20,37	€ 22,61	€ 24,98	€ 27,49
€ 36,50	€ 4,86	€ 5,62	€ 6,52	€ 7,55	€ 8,71	€ 10,01	€ 11,44	€ 13,01	€ 14,71	€ 16,55	€ 18,52	€ 20,62	€ 22,86	€ 25,24	€ 27,74
€ 46,50	€ 5,12	€ 5,88	€ 6,77	€ 7,80	€ 8,97	€ 10,27	€ 11,70	€ 13,27	€ 14,97	€ 16,80	€ 18,77	€ 20,88	€ 23,12	€ 25,49	€ 28,00
€ 56,50	€ 5,37	€ 6,13	€ 7,03	€ 8,06	€ 9,22	€ 10,52	€ 11,95	€ 13,52	€ 15,22	€ 17,06	€ 19,03	€ 21,13	€ 23,37	€ 25,74	€ 28,25
€ 66,50	€ 5,62	€ 6,38	€ 7,28	€ 8,31	€ 9,47	€ 10,77	€ 12,21	€ 13,77	€ 15,48	€ 17,31	€ 19,28	€ 21,39	€ 23,62	€ 26,00	€ 28,51
€ 76,50	€ 5,88	€ 6,64	€ 7,53	€ 8,56	€ 9,73	€ 11,03	€ 12,46	€ 14,03	€ 15,73	€ 17,57	€ 19,54	€ 21,64	€ 23,88	€ 26,25	€ 28,76
€ 86,50	€ 6,13	€ 6,89	€ 7,79	€ 8,82	€ 9,98	€ 11,28	€ 12,71	€ 14,28	€ 15,98	€ 17,82	€ 19,79	€ 21,89	€ 24,13	€ 26,51	€ 29,01
€ 96,50	€ 6,39	€ 7,15	€ 8,04	€ 9,07	€ 10,24	€ 11,54	€ 12,97	€ 14,54	€ 16,24	€ 18,07	€ 20,04	€ 22,15	€ 24,39	€ 26,76	€ 29,27
€ 106,50	€ 6,64	€ 7,40	€ 8,30	€ 9,33	€ 10,49	€ 11,79	€ 13,22	€ 14,79	€ 16,49	€ 18,33	€ 20,30	€ 22,40	€ 24,64	€ 27,01	€ 29,52
€ 116,50	€ 6,89	€ 7,65	€ 8,55	€ 9,58	€ 10,74	€ 12,04	€ 13,48	€ 15,04	€ 16,75	€ 18,58	€ 20,55	€ 22,66	€ 24,89	€ 27,27	€ 29,78
€ 126,50	€ 7,15	€ 7,91	€ 8,80	€ 9,83	€ 11,00	€ 12,30	€ 13,73	€ 15,30	€ 17,00	€ 18,84	€ 20,81	€ 22,91	€ 25,15	€ 27,52	€ 30,03
€ 136,50	€ 7,40	€ 8,16	€ 9,06	€ 10,09	€ 11,25	€ 12,55	€ 13,98	€ 15,55	€ 17,25	€ 19,09	€ 21,06	€ 23,16	€ 25,40	€ 27,78	€ 30,28
€ 146,50	€ 7,66	€ 8,42	€ 9,31	€ 10,34	€ 11,51	€ 12,81	€ 14,24	€ 15,81	€ 17,51	€ 19,34	€ 21,31	€ 23,42	€ 25,66	€ 28,03	€ 30,54
€ 156,50	€ 7,91	€ 8,67	€ 9,57	€ 10,60	€ 11,76	€ 13,06	€ 14,49	€ 16,06	€ 17,76	€ 19,60	€ 21,57	€ 23,67	€ 25,91	€ 28,28	€ 30,79
€ 176,50	€ 8,42	€ 9,18	€ 10,07	€ 11,10	€ 12,27	€ 13,57	€ 15,00	€ 16,57	€ 18,27	€ 20,11	€ 22,08	€ 24,18	€ 26,42	€ 28,79	€ 31,30

Note: Green signifies a lower cost than the reference vale for production and import from Tunisia (reference value 7.19 EUR/kg). Red signifies a higher cost than the reference value for Tunisia.

Due to a potential risk in Tunisia, there exists a sensitivity to changes in the WACC. As we can see from the Table 26 with a WACC exceeding 15%, the Levelized Cost of Hydrogen imported from Tunisia becomes more expensive than the locally produced hydrogen in Austria.

Table 26 - Sensitivity: LCOH produced and imported from Tunisia (EUR per kg of hydrogen) with varying WACC

WACC%	LCOH [EUR/kg]
10%	6,80
11%	6,89
12%	6,99
13%	7,10
14%	7,23
15%	7,36
16%	7,50
17%	7,65
18%	7,80
19%	7,96
20%	8,13
21%	8,31
22%	8,49
23%	8,67

Note: Green signifies a lower cost than the reference vale for production in Austria (reference value 7.40 EUR/kg). Red signifies a higher cost than the reference value for Austria.

Table 27 shows the LCOH change with alternating WACC and CAPEX for Tunisia.

Table 27 - Sensitivity: LCOH produced and imported from Tunisia (EUR per kg of hydrogen) with varying WACC and CAPEX

		CAPEX [kEUR/MW]														
		€ 891,00	€ 1 091,00	€ 1 291,00	€ 1 491,00	€ 1 691,00	€ 1 891,00	€ 2 091,00	€ 2 291,00	€ 2 491,00	€ 2 691,00	€ 2 891,00	€ 3 091,00	€ 3 291,00	€ 3 491,00	€ 3 691,00
WACC %	10%	6,00	6,80	7,73	8,80	10,00	11,33	12,80	14,40	16,14	18,01	20,02	22,16	24,43	26,84	29,39
	11%	6,08	6,89	7,83	8,91	10,11	11,46	12,94	14,55	16,29	18,17	20,19	22,34	24,62	27,04	29,59
	12%	6,18	6,99	7,94	9,03	10,24	11,60	13,08	14,71	16,46	18,35	20,38	22,53	24,83	27,25	29,82
	13%	6,28	7,10	8,06	9,16	10,38	11,75	13,24	14,87	16,64	18,54	20,57	22,74	25,04	27,48	30,05
	14%	6,39	7,23	8,20	9,30	10,54	11,91	13,41	15,05	16,83	18,74	20,78	22,96	25,27	27,72	30,30
	15%	6,51	7,36	8,34	9,45	10,70	12,08	13,60	15,25	17,03	18,95	21,00	23,19	25,51	27,97	30,56
	16%	6,64	7,50	8,49	9,61	10,87	12,26	13,79	15,45	17,24	19,17	21,23	23,43	25,76	28,23	30,83
	17%	6,78	7,65	8,65	9,78	11,05	12,45	13,98	15,66	17,46	19,40	21,47	23,68	26,02	28,50	31,11
	18%	6,93	7,80	8,81	9,96	11,23	12,65	14,19	15,87	17,69	19,64	21,72	23,94	26,29	28,78	31,40
	19%	7,08	7,97	8,99	10,14	11,43	12,85	14,41	16,10	17,92	19,88	21,98	24,20	26,57	29,06	31,69
	20%	7,24	8,13	9,16	10,33	11,63	13,06	14,63	16,33	18,16	20,13	22,24	24,48	26,85	29,36	32,00
	21%	7,40	8,31	9,35	10,52	11,83	13,28	14,85	16,57	18,41	20,39	22,51	24,76	27,14	29,66	32,31
	22%	7,57	8,49	9,54	10,72	12,04	13,50	15,09	16,81	18,67	20,66	22,78	25,04	27,44	29,96	32,63
	23%	7,75	8,67	9,73	10,93	12,26	13,72	15,32	17,06	18,92	20,93	23,06	25,33	27,74	30,28	32,95

Note: Green signifies a lower cost than the reference vale for production in Austria (reference value 7.40 EUR/kg). Red signifies a higher cost than the reference value for Austria.

If Tunisia were entirely powered by solar PV electricity, the levelized cost of hydrogen would be 6.74. In contrast, with exclusive reliance on wind energy, the LCOH would be 7.63. Figure 25 illustrates the LCOH across different electricity scenarios.

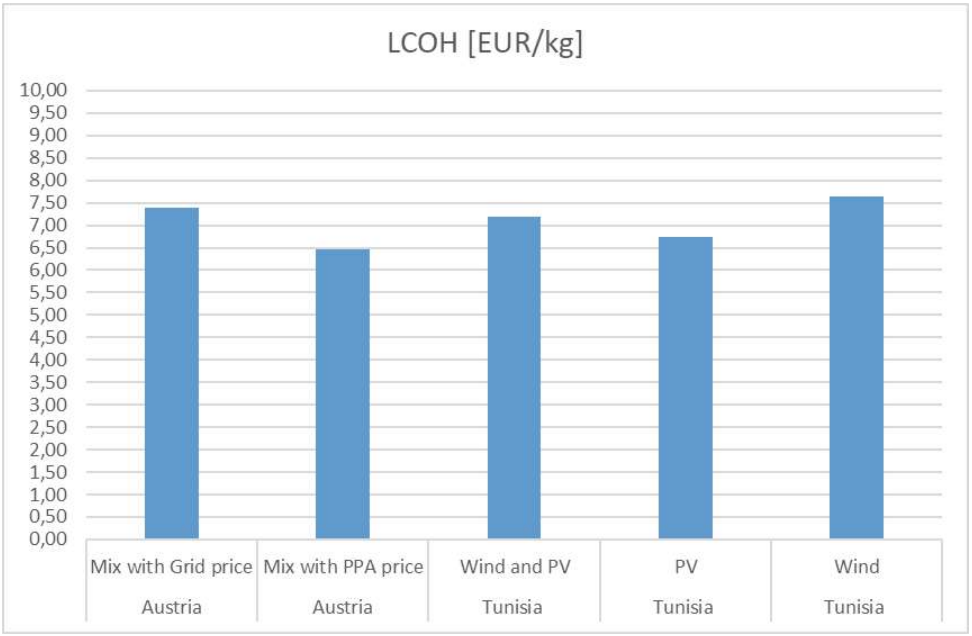


Figure 25 - LCOH (EUR/kg) with different electricity mixes for Austria and Tunisia

5.3.9 Revenue Potential

Since the cost competitiveness of green hydrogen and its by-products is currently below that of fossil fuels, the successful implementation depends on essential factors such as political backing and financial support. External influences, including carbon pricing schemes, technological readiness, global climate change priorities, national decarbonization goals, and private sector environmental strategies, will also shape the acceptance of higher prices for green hydrogen and its products in markets and the pace of technological advancement (GIZ, 2021).

Several authors, such as Nicita et al. (2020) and Da Silva et al. (2022) have examined the potential revenue generation or alternative uses of oxygen, leading to improved economic outcomes. However, it is important to note that this thesis does not focus on this aspect.

6 Life Cycle Analysis

The levels of emissions linked to hydrogen production can differ greatly depending on the production methods utilized, the type of fuel involved, the technologies employed, and the extent to which carbon capture and storage (CCS) is integrated. Apart from the direct emissions during hydrogen production, there are also indirect emissions arising from the sourcing, conversion, and transportation of the prerequisite input fuels like natural gas (IEA, 2023a, p.87).

In order to accelerate the growth of the green hydrogen sector, it is vital to address the disparity in costs between traditional grey hydrogen and environmentally friendly green hydrogen. Hydrogen produced from renewable sources remains financially uncompetitive when compared to hydrogen generated from fossil fuels (GIZ, 2021). A key strategy to combat this is through carbon pricing, which raises the cost of options that emit greenhouse gases and aids in narrowing this cost gap. The pricing mechanism should encompass all externalities linked to GHG emissions or be supplemented by additional policy tools to effectively incentivize the transition to cleaner energy alternatives.

In hydrogen production using SMR from natural gas, direct emissions are 9 kg CO2 equivalent per kg of hydrogen, with total emissions ranging from 10-13 kg CO2-eq/kg H2 without CCS. For hydrogen production from water electrolysis, emissions intensity varies depending on electricity generation and transportation factors, resulting in an intensity of 24 kg CO2-eq/kg H2 for the global electricity grid value (IEA, 2023a, p.88). However as for this comparison, considered are only CO2 emissions from electrolysis using solar and wind energy. It is worth to mention that regions like Sweden with environmentally friendly electricity production, the emissions intensity can drop to as low as 0.5 kg CO2-eq/kg H2 (IEA, 2023a, p.88)

Green hydrogen produced from solar energy is projected to have greenhouse gas emissions of 1.9kg CO2 per kg of hydrogen by 2035, whereas hydrogen produced from wind energy is expected to haver emissions of 0.5 kg CO2 per kilogram of hydrogen by the same year (Weidner, 2023, p.8319). Patel et al. (2024, p.1) noted that emissions from green hydrogen production using solar energy are 2.5kg per kilogram of hydrogen.

The Greenhouse Gas abatement cost serve also as a valuable key performance indicator (in comparing green hydrogen with fossil grey hydrogen). This metric quantifies the cost associated with reducing 1 kilogram of CO2 equivalent emissions through the transition from a reference method (grey hydrogen) to a new method (green hydrogen). The GHG abatement cost can be calculated using the following formula (Verma Aman, 2015):

$$G = \frac{LCOH_i - LCOH_{ref}}{LCE_{ref} - LCE_i} * 1000 \quad (10)$$

Where:

G … GHG Abatement Cost [EUR/t of CO2-eq]

LCOHi … LCOH of SMR scenario [EUR/kg of H2]

LCOHref … LCOH of green hydrogen scenario [EUR/kg H2]

LCEi … Life Cycle GHG Emissions of SMR scenario [kgCO2eq/kg of H2]

LCEref … Life Cycle GHG Emissions of green hydrogen scenario [kgCO2eq/kg of H2]

Before the global energy crisis triggered by Russia's invasion of Ukraine, the average levelized cost of producing hydrogen from fossil gas sources ranged between 1 and 3 USD per kilogram of hydrogen. However, with natural gas prices surging to unprecedented highs in 2022, the cost of fossil-based hydrogen production spiked to as much as 5.0 USD per kilogram (IEA, 2023a). This significant increase in fossil fuel prices provides another incentive for green hydrogen to become more competitive against fossil-derived hydrogen. IEA (2023a) estimates that the levelized cost of hydrogen coming from PV and wind ranges from 4-11 USD/kilogram of hydrogen.

The Frauenhofer Institute (2021) projects CO2 prices to range 80-120 EUR/t in 2030, 120-180 EUR/t in 2035 and 150-300 EUR/t in 2040. CO2 prices are going up due to rising climate targets.

Considering calculated LCOH for green hydrogen production in Austria and applying the formula for GHG abatement cost, the calculated GHG abatement cost is 600 EUR per ton of CO2 as shown in Table 28. This implies that if the CO2 price remains below 600 EUR, and additional profits are without factoring in additional profits, there would be limited incentive for a refinery to make investments in green hydrogen versus grey hydrogen.

Table 28 - GHG Abatement Cost Calculation

	Value	Unit	Source
LCOH (SMR)	2,0	EUR/kg H2	IEA, 2023a, p.80
LCOH (Green)	7,4	EUR/kg H2	Own Calculation (presented in 5.3.7)
Life Cycle GHG Emissions of SMR	11,5	kgCO2eq/kg of H2	IEA, 2023a, p.88
Life Cycle GHG Emissions of Green H2	2,5	kgCO2eq/kg of H2	Patel et al, 2024, p.1
GHG Abatement Cost	600,0	EUR/t of CO2	

It's worth noting that green hydrogen costs could potentially decrease. Additionally, calculated was the required LCOH for a GHG abatement cost of 200 EUR per ton, which is estimated to be the CO2 price in 2030 (The Frauenhofer Institute, 2021). To achieve a GHG abatement cost of 200 EUR/t of CO2, the costs of green hydrogen would have to be 3.80 EUR/kg of H2 as shown in Table 29.

Table 29 - LCOH to achieve GHG Abatement Cost of 200 EUR/t of CO2 (Break-Even GHG Abatement cost)

	Value	Unit	Source
LCOH (SMR)	2,0	EUR/kg H2	IEA, 2023a, p.80
LCOH (Green)	3,8	EUR/kg H2	Calculated
Life Cycle GHG Emissions of SMR	11,5	kgCO2eq/kg of H2	IEA, 2023a, p.88
Life Cycle GHG Emissions of Green H2	2,5	kgCO2eq/kg of H2	Patel et al, 2024, p.1
GHG Abatement Cost	200,0	EUR/t of CO2	(The Frauenhofer Institute, 2021)

7 Conclusion

The global energy landscape is facing significant challenges posed by climate change, energy security and the transition to renewable energy sources. Investing in green hydrogen production plants is a critical strategy for achieving sustainable energy transition. This technology has the potential to make a contribution to climate change mitigation on a global scale. The purpose of this thesis was to evaluate how green hydrogen could be produced using wind and solar energy in Austria, as well as in Tunisia, for the use in the refining industry in Austria to replace natural gas. In the thesis are developed various scenarios for wind and PV power procurement and assessed the cost of green hydrogen along with its sensitivity to key factors.

This thesis investigates one of the central debates in green hydrogen production, which is whether to produce it locally, in Austria, in this case, or to import it from regions with abundant renewable resources, such as North Africa. North Africa benefits from higher renewable energy potential and greater full load hours for solar and wind power compared to regions in Europe like Austria. This higher renewable energy potential offers a significant advantage for green hydrogen production in North Africa. However, there are inherent risks associated with import approach from North Africa, leading to higher costs of capital. These risks include political instability, potential logistical challenges, and infrastructural limitations. It is worth to mention that Tunisia can be distinguished with its relatively stable political and economic climate compared to other North African countries. Local production of green hydrogen in regions like Austria avoids these risks but faces limitations in renewable energy potential and FLH, which results in higher production costs per unit of hydrogen. Moreover, the cost-effectiveness of hydrogen is heavily dependent on electricity costs, which tend to be higher in areas with less abundant renewable resources.

Additionally, if Austria chooses to import hydrogen from another countries, such as those in North Africa, there is a risk of becoming energy dependent on external sources. To mitigate this, it would be advisable to incentivize local capital expenditures through policy measures, encouraging the development of renewable energy projects domestically to make them competitive with imports. High initial capital investments

should be supported by incentive policies that ease the integration of hydrogen in industrial applications, thus ensuring its competitiveness in the short term.

In today's hydrogen market, the expenses involved in producing green hydrogen continue to exceed those of grey hydrogen. This is largely a result of the capital expenditures and operational expenditures linked to renewable energy infrastructure.

Power Purchase Agreements (PPAs) have increasingly become a prevalent method for companies to obtain dedicated renewable energy. According to the current draft delegated act by the European Commission concerning RFNBO, utilizing PPA prices is permitted for securing renewable electricity. The thesis demonstrates that, with current pricing, this method is cost-effective. Moreover, using PPA-based renewable electricity allows for the installation of renewable energy projects in the locations with the highest potential of renewable electricity generation.

The GHG abatement cost analyzed suggests that for green hydrogen to be competitive with the existing grey hydrogen production, the CO2 price would need to be at least 600 EUR per tonne of CO2 or, in another words, the CO2 price would need to rise compared to current projections. Future efforts should be aimed at lowering CAPEX, reducing electricity costs, and improving process efficiencies. Continued research and innovation will be critical in overcoming the current limitations and unlocking the full potential of green hydrogen as a sustainable energy solution.

In analyzing the feasibility of green hydrogen production, it becomes evident that choosing the right location, leveraging proprietary technologies, and integrating into existing industrial contexts are vital strategies. Partnerships along the hydrogen supply chain and utilizing waste heat can further enhance cost-effectiveness by achieving economies of scale.

7.1 Limitations

While this thesis provides an in-depth examination of green hydrogen production costs, it is not without limitations. One significant constraint is the variability and lack of transparency in CAPEX data for electrolyzers. Studies often differ in what costs are

included and the components to which the learning curve is applied, leading to high uncertainty in the calculated levelized cost of hydrogen.

Additionally, costs other than CAPEX and electricity costs, though less documented in large reports, are vital. This thesis attempts to address all cost components, but the lack of transparent data may impact the accuracy of the analysis. Moreover, the evolving nature of the field means new technologies and geopolitical developments could soon alter the current landscape.

7.2 Future Research

Potential areas for future research could include exploring battery storage options for electricity, as well as delving deeper into the capital expenditure requirements for building a pipeline in Austria and considering more detailed cost considerations regarding this infrastructure. Also, potential research efforts might involve assessing the cost implications of building a desalination plant. An area for further investigation could involve examining the purity of transported hydrogen to ensure it meets the requisite quality standards for the refinery. This analysis may also entail assessing any potential additional investments required, such as incorporating Pressure Swing Adsorption (PSA) technology.

Some literatures suggest that transportation through pipelines may be more cost-effective than shipping, although a detailed comparison of these methods was not included in this study.

Exploring efficiencies across the entire value chain warrants further analysis. Another critical aspect to consider is the absence of well-defined hydrogen markets. Future research directions should involve a comprehensive examination of the entire refinery value chain and the utilization of hydrogen within it, emphasizing its use in the production of valuable products like sustainable aviation fuels and chemicals and exploring revenue opportunities in providing such sustainable offerings.

Moreover, future research should encompass a thorough evaluation of potential hydrogen storage solutions, emphasizing a detailed assessment of Austria's geological structures to ascertain the feasibility of geological storage methods.

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Appendix

A.1 Economic model

A.1.1 Levelized cost of electricity from solar PV (Austria)

	unit		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049
			0	1	2	3	4	5	6	7	8	9	10	11	12	13	13	15	16	17	18	19	20
Solar PV																							
Investment cost	kEUR	€	22 000,00																				
Operations and maintenance	kEUR	€		542,64 €	564,56 €	599,12 €	648,51 €	716,00 €	806,33 €	926,22 €	1 085,22 €	1 296,94 €	1 580,96 €	1 965,73 €	2 493,02 €	3 224,98 €	4 171,86 €	5 614,77 €	7 707,88 €	10 792,89 €	15 414,90 €	22 456,60 €	33 369,33
Land cost	kEUR	€		- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	-
Generation		€		47 444,53 €	- €	176 158,45 €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	- €	-
Depreciation	kEUR	€		1 100,00 €	1 100,00 €	1 100,00 €	1 100,00 €	1 100,00 €	1 100,00 €	1 100,00 €	1 100,00 €	1 100,00 €	1 100,00 €	1 100,00 €	1 100,00 €	1 100,00 €	1 100,00 €	1 100,00 €	1 100,00 €	1 100,00 €	1 100,00 €	1 100,00 €	1 100,00
Nominal Costs Solar	kEUR	€	22 000,00 €	542,64 €	564,56 €	599,12 €	648,51 €	716,00 €	806,33 €	926,22 €	1 085,22 €	1 296,94 €	1 580,96 €	1 965,73 €	2 493,02 €	3 224,98 €	4 171,86 €	5 614,77 €	7 707,88 €	10 792,89 €	15 414,90 €	22 456,60 €	33 369,33
Discounted Costs Solar	kEUR	€	22 000,00 €	513,01 €	504,60 €	506,25 €	518,06 €	540,75 €	575,73 €	625,22 €	692,55 €	782,48 €	901,76 €	1 060,01 €	1 270,95 €	1 554,35 €	2 010,71 €	2 418,73 €	3 139,11 €	4 155,53 €	5 611,08 €	7 727,59 €	10 856,43
NPV Costs	kEUR	€	67 965,29																				
NPV of Generation		€	554 803,59																				
CRF		€	0,09																				
Annuity of Costs	kEUR	€	5 817,75																				
Energy produced	MWh/year			47 444,53 €	47 444,53 €	47 444,53 €	47 444,53 €	47 444,53 €	47 444,53 €	47 444,53 €	47 444,53 €	47 444,53 €	47 444,53 €	47 444,53 €	47 444,53 €	47 444,53 €	47 444,53 €	47 444,53 €	47 444,53 €	47 444,53 €	47 444,53 €	47 444,53 €	47 444,53
Energy produced discounted				44 854,20 €	42 405,29 €	40 090,09 €	37 901,29 €	35 831,99 €	33 875,67 €	32 026,16 €	30 277,63 €	28 624,56 €	27 061,74 €	25 584,25 €	24 187,43 €	22 866,87 €	22 866,87 €	20 488,10 €	19 322,24 €	18 267,31 €	17 269,97 €	16 327,08 €	15 435,67
LCOE (Weißensteiner, 2022)	kEUR/MWh	€	0,14																				

	unit		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042	2044	2045	2046	2047	2048	2049
			0	1	2	3	4	5	6	7	8	9	10	11	12	13	13	15	16	17	18	19	20
Solar PV																							
Investment cost	kEUR		€ 55 000,00																				
Operations and maintenance	kEUR			€ 876,18	€ 911,58	€ 967,37	€ 1 047,12	€ 1 156,10	€ 1 301,96	€ 1 495,54	€ 1 752,26	€ 2 094,12	€ 2 552,72	€ 3 173,98	€ 4 025,38	€ 5 207,25	€ 6 736,14	€ 9 065,96	€ 12 445,61	€ 17 426,87	€ 24 889,85	€ 36 259,82	€ 53 880,18
Land cost	kEUR			€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -
Generation				€ 176 158,45	€ -	€ 176 158,45	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -
Depreciation	kEUR			€ 2 750,00	€ 2 750,00	€ 2 750,00	€ 2 750,00	€ 2 750,00	€ 2 750,00	€ 2 750,00	€ 2 750,00	€ 2 750,00	€ 2 750,00	€ 2 750,00	€ 2 750,00	€ 2 750,00	€ 2 750,00	€ 2 750,00	€ 2 750,00	€ 2 750,00	€ 2 750,00	€ 2 750,00	€ 2 750,00
Nominal Costs Solar	kEUR		€ 55 000,00	€ 876,18	€ 911,58	€ 967,37	€ 1 047,12	€ 1 156,10	€ 1 301,96	€ 1 495,54	€ 1 752,26	€ 2 094,12	€ 2 552,72	€ 3 173,98	€ 4 025,38	€ 5 207,25	€ 6 736,14	€ 9 065,96	€ 12 445,61	€ 17 426,87	€ 24 889,85	€ 36 259,82	€ 53 880,18
Discounted Costs Solar	kEUR		€ 55 000,00	€ 770,74	€ 705,38	€ 658,48	€ 626,99	€ 608,94	€ 603,24	€ 609,55	€ 628,24	€ 660,46	€ 708,21	€ 774,60	€ 864,17	€ 983,37	€ 1 272,09	€ 1 324,81	€ 1 599,82	€ 1 970,56	€ 2 475,76	€ 3 172,70	€ 4 147,13
NPV Costs	kEUR	€ 80 165,25																					
NPV of Generation		€ 1 189 469,93																					
CRF		€ 0,15																					
Annuity of Costs	kEUR	€ 11 881,09																					
Energy produced	MWh/year			€ 176 158,45	€ 176 158,45	€ 176 158,45	€ 176 158,45	€ 176 158,45	€ 176 158,45	€ 176 158,45	€ 176 158,45	€ 176 158,45	€ 176 158,45	€ 176 158,45	€ 176 158,45	€ 176 158,45	€ 176 158,45	€ 176 158,45	€ 176 158,45	€ 176 158,45	€ 176 158,45	€ 176 158,45	€ 176 158,45	€ 176 158,45
Energy produced discounted				€ 154 959,93	€ 136 312,40	€ 119 908,87	€ 105 479,30	€ 92 786,15	€ 81 620,47	€ 71 798,44	€ 63 158,38	€ 55 558,04	€ 48 872,31	€ 42 991,12	€ 37 817,67	€ 33 266,77	€ 33 266,77	€ 25 742,01	€ 22 644,28	€ 19 919,31	€ 17 522,27	€ 15 413,68	€ 13 558,83
LCOE (Weißensteiner, 2022)	kEUR/MWh	€ 0,07																					

	unit		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042	2044	2045	2046	2047	2048	2049
Wind																							
Investment cost	kEUR		€ 50 400,00																				
Operations and maintenance	kEUR			€ 672,35	€ 699,51	€ 742,33	€ 803,52	€ 887,15	€ 999,08	€ 1 147,63	€ 1 344,63	€ 1 606,95	€ 1 958,87	€ 2 435,60	€ 3 088,93	€ 3 995,87	€ 5 169,08	€ 6 956,90	€ 9 550,33	€ 13 372,77	€ 19 099,61	€ 27 824,53	€ 41 345,78
Land cost	kEUR			€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -
Nominal Costs Wind	kEUR		€ 50 400,00	€ 672,35	€ 699,51	€ 742,33	€ 803,52	€ 887,15	€ 999,08	€ 1 147,63	€ 1 344,63	€ 1 606,95	€ 1 958,87	€ 2 435,60	€ 3 088,93	€ 3 995,87	€ 5 169,08	€ 6 956,90	€ 9 550,33	€ 13 372,77	€ 19 099,61	€ 27 824,53	€ 41 345,78
Discounted Costs Wind	kEUR		€ 50 400,00	€ 635,64	€ 625,22	€ 627,26	€ 641,90	€ 670,01	€ 713,35	€ 774,67	€ 858,10	€ 969,52	€ 1 117,31	€ 1 313,39	€ 1 574,75	€ 1 925,89	€ 2 491,34	€ 2 996,89	€ 3 889,47	€ 5 148,85	€ 6 952,32	€ 9 575,25	€ 13 451,49
NPV Costs	kEUR	€ 107 352,61																					
CRF		€ 0,09																					
Annuity of Costs	kEUR	€ 9 189,26																					
LCOE (W, 2022)	kEUR/MWh	€ 0,08																					

	unit		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042	2044	2045	2046	2047	2048	2049
			0	1	2	3	4	5	6	7	8	9	10	11	12	13	13	15	16	17	18	19	20
Wind																							
Investment cost	kEUR		€ 60 000,00																				
Operations and maintenance	kEUR			€ 983,52	€ 1 023,26	€ 1 085,89	€ 1 175,40	€ 1 297,74	€ 1 461,46	€ 1 678,76	€ 1 966,94	€ 2 350,67	€ 2 865,45	€ 3 562,83	€ 4 518,53	€ 5 845,20	€ 7 561,40	€ 10 176,64	€ 13 970,35	€ 19 561,86	€ 27 939,16	€ 40 702,08	€ 60 481,14
Land cost	kEUR			€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -
Nominal Costs Wind	kEUR		€ 60 000,00	€ 983,52	€ 1 023,26	€ 1 085,89	€ 1 175,40	€ 1 297,74	€ 1 461,46	€ 1 678,76	€ 1 966,94	€ 2 350,67	€ 2 865,45	€ 3 562,83	€ 4 518,53	€ 5 845,20	€ 7 561,40	€ 10 176,64	€ 13 970,35	€ 19 561,86	€ 27 939,16	€ 40 702,08	€ 60 481,14
Discounted Costs Wind	kEUR		€ 60 000,00	€ 865,17	€ 791,80	€ 739,15	€ 703,80	€ 683,54	€ 677,15	€ 684,23	€ 705,21	€ 741,37	€ 794,97	€ 869,50	€ 970,04	€ 1 103,84	€ 1 427,94	€ 1 487,11	€ 1 795,82	€ 2 211,98	€ 2 779,07	€ 3 561,39	€ 4 655,20
NPV Costs	kEUR	€ 88 248,29																					
CRF		€ 0,15																					
Annuity of Costs	kEUR	€ 13 079,05																					
LCOE (W, 2022)	kEUR/MWh	€ 0,09																					

A.1.5 Levelized cost of hydrogen (Austria)

Cost Parameter	unit	Austria
Electrolyzer Capex		
Plant lifetime	years	20
Hydrogen Output	kg/h	686
Hydrogen Output	kg/y	5.833.333
Hydrogen Energy Content	kWh/kg	39,40
Electrolyzer Efficiency	%	70%
Electricity Required	kWh/kg H2	56,29
Electricity Required	kWh/y	328.333.333
Electrolyzer Full Load Hours	h/y	8.500
Electrolyzer Capacity	MW	38,63
Electrolyzer CAPEX PEM	kEUR/MW	1.091
Total Electrolyzer CAPEX	**kEUR**	**42.132,89**
Electrolyzer OPEX		
Required electricity input from the grid	MWh/y	182.512,55
Electricity price (EU mix, 2030)	eur/MWh	106,50
Total electricity cost	**kEUR**	**19.437,59**
Deionised water specific demand	kg/kg H2	10
Deionised water cost	EUR/kg	0,01
Steam specific demand (Process Steam used during run-up to heat up the system)	kg/kg H2	0,11
Steam cost	EUR/kg	0,01
Nitrogen specific demand (Used for cleaning purpose)	g/kg H2	0,29
Nitrogen cost	EUR/kg	0,28
Total Utilities Cost	**kEUR**	**590,22**
O&M	% of investment cost	3%
Pipeline Length	km	0
Pipeline transportation cost	eur/kg	0,00
Total pipeline transportation cost	**kEUR**	**-**
Revenue		

Location: Austria	Share	Price [eur/MWh]
Solar	14%	€ 135,55
Wind	33%	€ 82,18
Grid	53%	€ 106,50

Electricity mix price € 102,58 eur/MWh

	unit		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042	2044	2045	2046	2047	2048	2049
			0	1	2	3	4	5	6	7	8	9	10	11	12	13	13	15	16	17	18	19	20
Electrolyzer																							
Investment	kEUR		$ 42 132,89																				
Electricity purchase from the grid	kEUR			$ 19 826,34	$ 20 627,32	$ 21 889,88	$ 23 694,31	$ 26 160,43	$ 29 460,90	$ 33 841,31	$ 39 650,49	$ 47 386,00	$ 57 763,27	$ 71 821,37	$ 91 086,86	$ 117 830,57	$ 152 426,41	$ 205 145,88	$ 281 621,33	$ 394 337,84	$ 563 211,55	$ 820 492,87	$ 1 219 209,25
Utilities Cost	kEUR			$ 602,03	$ 626,35	$ 664,68	$ 719,48	$ 794,36	$ 894,58	$ 1 027,59	$ 1 203,98	$ 1 438,87	$ 1 753,98	$ 2 180,85	$ 2 765,85	$ 3 577,92	$ 4 628,42	$ 6 229,24	$ 8 551,41	$ 11 974,04	$ 17 101,87	$ 24 914,20	$ 37 021,19
O&M	kEUR																						
Land costs	kEUR																						
Pipeline transportation Cost	kEUR			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Nominal Costs electrolyzer	kEUR		$ 42 132,89	$ 20 428,36	$ 21 253,67	$ 22 554,56	$ 24 413,79	$ 26 954,79	$ 30 355,47	$ 34 868,90	$ 40 854,47	$ 48 824,88	$ 59 517,25	$ 74 002,22	$ 93 852,71	$ 121 408,49	$ 157 054,82	$ 211 375,11	$ 290 172,73	$ 406 311,88	$ 580 313,42	$ 845 407,08	$ 1 256 230,44
Discounted Costs electrolyzer	kEUR		$ 42 132,89	$ 19 313,04	$ 18 996,25	$ 19 058,35	$ 19 503,07	$ 20 357,33	$ 21 673,99	$ 23 537,32	$ 26 072,06	$ 29 457,36	$ 33 947,87	$ 39 905,37	$ 47 846,53	$ 58 515,32	$ 75 695,81	$ 91 055,95	$ 118 175,67	$ 156 440,05	$ 211 236,03	$ 290 929,82	$ 408 703,76
NPV Costs	kEUR	$ 1 947 871,7																					
CRF		$ 0,09																					
Annuity of Costs	kEUR	$ 166 735,6																					
LCOH (Agora, Frauenhof)	EUR/kg	€ 7,40																					

A.1.6 Levelized cost of hydrogen (Tunisia)

Cost Parameter	unit	Tunisia
Electrolyzer Capex		
Plant lifetime	years	20
Hydrogen Output	kg/h	686
Hydrogen Output	kg/y	5.833.333
Hydrogen Energy Content	kWh/kg	39,40
Electrolyzer Efficiency	%	70%
Electricity Required	kWh/kg H2	56,29
Electricity Required	kWh/y	328.333.333
Electrolyzer Full Load Hours	h/y	8.500
Electrolyzer Capacity	MW	38,63
Electrolyzer CAPEX PEM	kEUR/MW	1.091
Total Electrolyzer CAPEX	**kEUR**	**42.132,89**
Electrolyzer OPEX		
Required electricity input from the grid	MWh/y	-
Electricity price (EU mix, 2030)	eur/MWh	106,50
Total electricity cost	**kEUR**	**-**
Deionised water specific demand	kg/kg H2	10
Deionised water cost	EUR/kg	0,01
Steam specific demand (Process Steam used during run-up to heat up the system)	kg/kg H2	0,11
Steam cost	EUR/kg	0,01
Nitrogen specific demand (Used for cleaning purpose)	g/kg H2	0,29
Nitrogen cost	EUR/kg	0,28
Total Utilities Cost	**kEUR**	**590,22**
O&M	% of investment cost	3%
Pipeline Length	km	3000
Pipeline transportation cost	eur/kg	0,63
Total pipeline transportation cost	**kEUR**	**-**

Location: Tunisia	Share	Price [eur/MWh]
Solar	50%	€ 67,45
Wind	50%	€ 86,14
Grid	0%	€ -

Electricity mix price € 76,79 eur/MWh

	unit		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042	2044	2045	2046	2047	2048	2049
			0	1	2	3	4	5	6	7	8	9	10	11	12	13	13	15	16	17	18	19	20
Electrolyzer																							
Investment	kEUR		$ 42 132,89																				
Electricity purchase from the grid	kEUR			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Utilities Cost	kEUR			$ 602,03	$ 626,35	$ 664,68	$ 719,48	$ 794,36	$ 894,58	$ 1 027,59	$ 1 203,98	$ 1 438,87	$ 1 753,98	$ 2 180,85	$ 2 765,85	$ 3 577,92	$ 4 628,42	$ 6 229,24	$ 8 551,41	$ 11 974,04	$ 17 101,87	$ 24 914,20	$ 37 021,19
O&M	kEUR																						
Land costs	kEUR																						
Pipeline transportation Cost	kEUR			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Nominal Costs electrolyzer	kEUR		$ 42 132,89	$ 602,03	$ 626,35	$ 664,68	$ 719,48	$ 794,36	$ 894,58	$ 1 027,59	$ 1 203,98	$ 1 438,87	$ 1 753,98	$ 2 180,85	$ 2 765,85	$ 3 577,92	$ 4 628,42	$ 6 229,24	$ 8 551,41	$ 11 974,04	$ 17 101,87	$ 24 914,20	$ 37 021,19
Discounted Costs electrolyzer	kEUR		$ 42 132,89	$ 529,58	$ 484,67	$ 452,44	$ 430,80	$ 418,40	$ 414,49	$ 418,82	$ 431,67	$ 453,80	$ 486,61	$ 532,23	$ 593,77	$ 675,67	$ 874,06	$ 910,28	$ 1 099,24	$ 1 353,98	$ 1 701,10	$ 2 179,97	$ 2 849,50
NPV Costs	kEUR	$ 227 837,5																					
CRF		$ 0,15																					
Annuity of Costs	kEUR	$ 33 767,2																					
LCOH (Agora, Frauenhof)	EUR/kg	€ 7,19																					